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Chapter 4 - Alternative System Improvements in Wisconsin

This chapter considers how alternative system improvements other than a major new transmission line could meet the capacity need in Wisconsin. These alternatives include: no action (no change in the current status of generation or transmission plant), merchant plants, rate-based power plants, energy efficiency, market-based curtailable load programs, real-time pricing, and distributed and renewable resource generation. The last part of the chapter discusses using an integrated approach with other types of smaller transmission system improvements to meet future capacity needs. The environmental effects of implementing the alternative system improvements are also described.

The analysis in this chapter examines various aspects of alternatives to the proposed line, one at a time. In some cases, the analysis and discussion bearing on a single aspect of an alternative to the line may arrive at a particular observation or result. These singular observations should not be taken out of context. The complexity, size, and scope of the Arrowhead-Weston Transmission Project project require a balanced consideration of all the important factors.

Background

In Wisconsin, generation construction has traditionally been used to meet expanding needs. Between 1975 and 1999, 26 units were installed at 11 power plant sites, totaling 4,645 MW. These include Columbia 1 (1975, 527 MW), Germantown (4 units, 1978, 75 MW each), Columbia 2 (1978, 527 MW), Pleasant Prairie (2 units, 1980 and 1985, 600 MW each), Weston 3 (1981, 334 MW), Edgewater 5 (1985, 382 MW), West Marinette (1993, 83 MW), South Fond du Lac, (4 units, 1993-1996, 85 MW each), Concord (4 units, 1993-1994, 79 MW each), Paris (4 units, 1995, 79 MW each), LS Power -Whitewater (1997, 227 MW), and Polsky Energy Center (1999, 1 unit, 180 MW).

History also shows that major 345 kV transmission facilities have been a significant means of meeting Wisconsin's expanding population, economic, and reliability needs. The Wisconsin utilities have constructed several major 345 kV transmission lines. During the mid-1960s the King-North Appleton line, which crosses the state over 250 miles from north of Appleton to west of Eau Claire, was put in service. In 1969, transmission reinforcements related to the Edgewater generating plant near Sheboygan were put in service. During the 1970 to 1973 time frame, 345 kV transmission facilities associated with the Point Beach and Kewaunee nuclear power units were constructed from near Manitowoc to the northwest Milwaukee area. During 1975 and 1976, transmission improvements were put in place by MGE and WP&L to handle the new Columbia coal-fired power plant near Portage. These improvements were over 100 miles long and stretched from the Columbia power plant to the Illinois state line. In 1978, WPSC constructed 28 miles of 345 kV transmission line from the Weston electric generating power plant to a substation near Antigo. From 1980 to 1982, smaller 345 kV transmission improvements were installed to assist the new coal-fired power plant located at Pleasant Prairie. In 1999, WEPCO energized 72 miles of 345 kV transmission lines from Quinnesec, Michigan, to Oconto Falls. Lastly, in mid-1999 WEPCO received Commission authority to convert a 230 kV line between Oak Creek and Arcadian to 345 kV.

Traditionally, a blend of transmission and generation projects plus energy efficiency has been used to keep up with increased electric demand due to economic and population growth. Using such a blend provides diversification of supply source, thereby contributing to a reduction in supply risk. Any such reduction in supply risk directly contributes to the overall reliability of the statewide electric system and reduces the potential for substantial adverse impacts on ratepayers.

During the last 20 years, the Commission has regulated the planning and construction of both generating stations and transmission facilities and energy efficiency programs. This will not be the case in the future. 1997 Wisconsin Act 204 changed the Commission's role with respect to the economic regulation of electric power plant construction. Whereas during the past 20 years the Commission played a significant role in planning and siting electric generating plants, in the future, competitive market forces in wholesale power markets will drive the need for power plant construction. This change in state policy affects the fundamental manner in which power plants will come to fruition, creating the opportunity that competitive market forces may result in power plant construction that offsets some transmission facility needs in the state. 1999 Wisconsin Act 9 requires transmission utilities to transfer control of their transmission facilities to an ISO or an independent transmission owner whose responsibilities will include planning, constructing, operating, and maintaining the facilities. Significant changes in the oversight and implementation of energy efficiency programs also are contained in this statute. The effects of these legislative changes and how they impact the need for and alternatives to the Arrowhead-Weston Transmission Project are discussed in more detail in later sections of this chapter.

The No-Build Alternative

Under this alternative, no PSCW action is taken with respect to construction of a major new transmission line or the ordering of new power plant construction. For reasons made clear in Chapter 2 regarding continuing population, employment, and electricity usage growth, doing nothing is not a viable alternative. Using the existing transmission system and power generation facilities, as is, would not provide adequate or reliable service by the end of 2007. No action with respect to the construction of power plants or transmission lines would place the state's residential, commercial, and industrial customers and their business, health, safety, and welfare at risk of being without electricity. Doing nothing would lead to significant hardship and substantial economic losses in Wisconsin.

As Chapter 2 indicates, over the time frame 1998 to 2007 Wisconsin is expected to have nearly 2,400 MW of new electric demand. This increase in electric demand can be met by a combination of new electric generating facilities, an expansion of the ability to purchase or import electric power from other states and regions, as well as energy efficiency efforts. In order to meet this level of need and maintain reliability in the state, some generation or transmission projects or energy efficiency or a combination of these alternatives are needed.

Reliance on the Competitive Wholesale Market

As indicated above, a policy of no action would be unwise. This does not mean, however, that the PSCW must order public utility construction of either rate-based utility power plants or major new transmission lines. Instead, in response to changes in state law, the PSCW could rely as an alternative on the recently deregulated competitive wholesale power market wherein IPPs and others can construct wholesale merchant power plants. A wholesale merchant power plant refers to an electric generating facility owned and operated by a private developer that sells its electricity into a competitive open market. There is no guarantee of cost recovery for a merchant power plant as compared to a rate based public utility facility. In addition, developers of merchant power plants are free of PSCW economic regulation and choose to construct generating facilities in response to demand and supply conditions in the relevant area of interest.

Merchant power plants as an Arrowhead-Weston alternative

In recent years, the eastern Wisconsin utilities and two IPPs have built generation to meet increasing customer electric demands so that reserve margins of 18 percent are maintained. Other generation capacity additions are also in operation, in progress, or planned in eastern Wisconsin. Air inlet coolers are being added by the state's utilities at several existing combustion turbines to provide around 50 MW of additional capacity. SEI Wisconsin LLC's 300 MW, two-unit combustion turbine project began commercial service in May 2000 in Winnebago County. Another IPP project began construction in April of this year. That project is SkyGen (formally known as RockGen) Energy LLC's 450 MW, three-unit combustion-turbine project in Dane County, which is expected to be operational in 2001. Moreover, SkyGen Energy's De Pere (formerly known as Polsky) Energy Center, which received its CPCN from the PSCW in 1997 and began service in June 1999, is expected to add 55 MW of additional capacity in 2004.

In addition to these IPP developments, the state's utilities have also been constructing electric generating power plants. WEPCO is placing a new 83 MW combustion turbine in Germantown; MGE is contracting with WPSC for installation of an 83 MW combustion turbine in Marinette; and Manitowoc Public Utilities has installed a 25 MW combustion turbine in its service territory.

1997 Wisconsin Act 204 provided that the decision to build wholesale electric generating plants should follow competitive market forces, with the specific driver being price signals. A competitive market will indicate the need for new power plants by the existence of higher than usual power prices. Moreover, congestion on the state's electrical transmission system and associated usage tariffs can highlight areas where strategically located generation may be able to substitute for transmission improvements. The key question is: Can reliance on competitive markets obviate the need for a transmission improvement the size of the Arrowhead-Weston line? This is a difficult question with a mixed answer, requiring the review of certain facts.

As indicated earlier, during the 1990s nearly 1,500 MW of new generation was added in the state when construction was economically regulated by the Commission. Moreover, from 1998 to 2007, nearly 1,900 MW and 2,400 MW of new electric demand is expected in the EWU and state, respectively. This amount of new load will likely need to be met principally by a combination of energy efficiency, merchant plant construction, and the import of power.[66] As discussed in Chapter 2 (Table 2-3) and the application for the proposed project, 1,560 MW of new generating capacity would need to be added between 2000 and 2007 in order to preserve an 18 percent reserve margin and maintain a 0.1 day per year LOLE. In such a situation approximately 1,000 MW of import capability would need to exist. This is about the level of existing import capability.

If 1,560 MW of merchant power plant capacity were to be constructed at strategically located sites, then the need for the significant expansion of import capability could be diminished at least through the year 2007. There is some probability of that occurring.

Recently, another new developer of a wholesale merchant power plant has come forth and applied for Commission CPCN approval. On December 28, 1999, Badger Generating proposed a 1,050 MW facility to be located in the village of Pleasant Prairie in Kenosha County or near Sturtevant in Racine County. Hearings were held in July 2000 and a Commission decision is expected in the next few months. The Badger Generating facility would be comprised of four combined-cycle units. The Badger Generating plant is expected to be operational in 2003. Should the Badger Generating plant be approved and constructed, Wisconsin's electrical system reliability would be enhanced to the extent the facility sold either firm or non-firm power to the state's utilities or allowed more electricity imports over the southern interface. At this time, no Wisconsin utility has entered into a contract for delivery of all or a portion of the Badger Generating Plant output.

In addition, WP&L issued a RFP on April 25, 2000, in order to obtain approximately 500 MW of additional electric capacity. This process may result in the construction of new rate-based or wholesale merchant power plant generation in Wisconsin. WP&L will be evaluating all proposals submitted in response to the RFP. It is WP&L's goal to have 300 MW of additional electric capacity by 2002 and the remaining 200 MW the following year. Combining both the Badger Generating facility and the potential capacity procured under WP&L's RFP would add 1,550 MW of electric generation in Wisconsin by 2004.

[66] This assumes that the Commission does not order a public utility to construct rate-based generation facilities, and that public utilities are reluctant to build such facilities on their own.

Both the Badger Generating CPCN application and WP&L's RFP process represent known, formal actions involving merchant power plants. Several other potential power plant development projects are at varying stages. Two merchant plant developers have submitted engineering plans to the DNR, which is a necessary prerequisite to filing an application with the Commission. Fox Energy Company, LLC, filed engineering plans for between 530 and 630 MW of generation at two alternative sites in Outagamie County. Southern Energy, Inc. filed plans for 550 MW or more of generation at two alternative sites in Portage County. Both proposals are for gas-fired plants.

During the year 2000, several additional IPP have announced in the press or expressed to Commission staff a likelihood for additional wholesale merchant power plant construction in the state. Specifically, Commission staff is aware of the potential for the following merchant power plant facilities: 300 MW of combustion turbine capacity by Midwest Power Systems; 750 MW of combined cycle capacity by Calpine Central L.P.; and 300 MW of combustion turbine capacity by LS Power. These announcements reflect the potential for a vibrant wholesale merchant power plant market developing in Wisconsin over the next five years. Should these projects reach fruition, the need for the sizeable expansion of import capability that would occur with the Arrowhead-Weston transmission could be further diminished.

Although there is a strong possibility that merchant power plant construction could exceed 1,560 MW by the end of 2007, relying on merchant power plant construction alone to obviate the need for any increased transmission transfer capability would not necessarily be wise public policy. This is because the siting of merchant power plants would have to be timely and well-placed on the state's electric transmission system. Moreover, reliance on just one form of supply to meet growing demand creates its own risks. Traditionally, a blend of transmission and generation projects, plus energy efficiency, has been used to keep up with economic and population growth. Using such a blend provides diversification of supply source, thereby contributing to a reduction in supply risk. Any such reduction in supply risk directly contributes to the overall reliability of the statewide electric transmission system. Diversification can also lead to lower total costs.[67]

Overall, merchant power plant construction could substantially reduce the need for the additional 2,200 MW of transfer capability that the Arrowhead-Weston Transmission Project would create. Reliance on the use of merchant power plant capacity to entirely replace this line would increase supply source risk. Some increase in transmission transfer capability or other transmission upgrades would diversify supply source risk and provide additional opportunities to gain from the regional trading of electric power which provides the benefit of moving lower-cost power to higher-cost areas. However, with some moderate degree of merchant power plant

[67] An additional benefit of using merchant power plants is that plant operation risk is borne by the private owners of the merchant facility. This is unlike the public utility situation, in which ratepayers could face that risk.

construction, the appropriate increase in transmission transfer capability could likely be below 2,200 MW.[68]

Reliance on Rate-Based Power Plants

Rather than relying on the construction of electric generating plants by IPPs, Wisconsin utilities would voluntarily build (or issue RFPs for) new generation plant or the PSCW would order public utility construction of rate-based utility power plants. 1999 Wisconsin Act 9 grants specific authority to the Commission to order a public utility to make adequate investments in its facilities to ensure reliable electric service.[69] This means that the Commission could order public utilities to construct appropriate electric generating facilities in lieu of construction of a major new transmission line. Before doing so the Commission would need to conduct the appropriate investigation.

In addition to WP&L's proposal for 500 MW of additional electric capacity, WEPCO has indicated that it plans to add 1,700 MW of generation capacity at two of its existing generation plant sites over the next ten years. The plans, relying on a fuel mix of coal and natural gas, include at least one 500 MW combined-cycle unit at the Port Washington Power Plant and two 600 MW coal-fired units at the Oak Creek Plant or the Pleasant Prairie Plant. The 500 MW capacity addition at Port Washington would burn natural gas and would replace the existing coal-fired units, whose capacity totals approximately 350 MW.[70]

Load Reduction Alternatives

Conservation and energy efficiency

Energy efficiency includes energy conservation, fuel switching, and load management. Energy conservation reduces the use of electric energy. Fuel switching replaces the use of electricity with the use of another fuel, such as natural gas. Load management reduces the peak demand for electricity during a specific period. Utility energy efficiency efforts are also called demand-side management (DSM).

Examples of energy conservation include installing more efficient appliances, improving building insulation, redesigning industrial processes to use less energy, or reducing lighting loads through

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[68] The WRAO report justifies a need for 2,200 MW of additional transmission transfer capacity by using a an unrealistic scenario that assumes merchant power plant developers will not construct any electric power generating facilities through the year 2007, and that future Commission regulation is ineffective at requiring utilities either to procure power or build their own power plants. Such an assumption simultaneously predicts the failure of recently deregulated wholesale power markets and economic regulation.

[69] See Wis. Stat. § 196.487.

[70] WEPCO has indicated an interest in having these plants be part of a wholesale merchant power plant subsidiary. This would require some statutory changes. For this reason, these plants have been discussed in this section.

use of solar daylighting. Examples of fuel switching include replacing electric appliances such as water heaters and clothes dryers with natural gas appliances, and using natural gas or propane for heating fuel instead of electric heat. Examples of load management include programs that control air conditioner loads during times of extreme demands for electric power, and programs that provide monetary incentives for large users of electricity to shed loads upon request by their utility (interruptible rates).

Benefits of energy efficiency

The applicants have stated that the proposed power lines are needed to improve system reliability by reducing the chances that power outages will occur. Outages would occur when the demand for electricity exceeds the available supply. To correct such a situation, one can increase the supply or decrease the demand. Power plants and power lines address the problem by increasing supply. Energy efficiency addresses the problem by reducing demand for or use of electricity.

Because these power lines are being proposed primarily to address reliability problems that occur at a time of system peak usage of electricity, efficiency measures that reduce use of electricity at those times could substitute for supply measures. Management of loads that are likely to be on-line at the peak times of concern is one option. Load management will reduce the peak directly. General energy conservation can also contribute to addressing the peak need for power if the energy being saved is normally used during peak periods. For example, if an office's lights are on during peak periods, then improving the efficiency of the lighting will reduce energy use, and thus reduce the peak demand.

Using energy efficiency to meet system electric needs can have both economic and environmental advantages over using supply resources such as power plants and power lines.

The most significant economic advantage is that, if cost-effective, energy efficiency can reduce customer's electric bills. This can help make Wisconsin businesses more competitive. By reducing the amount of money spent on energy in Wisconsin, energy efficiency can also improve the state's economy in general. This is because most of every dollar spent on coal, natural gas, or uranium leaves Wisconsin and our economy.

From an environmental perspective, energy efficiency is the best option for meeting energy needs. Conservation and some forms of fuel switching reduce air pollution, water use, coal and uranium mining, disposal of radioactive waste, production of greenhouse gases, and the depletion of non-renewable resources. All three forms of energy efficiency reduce the need for power plants and power lines, thereby reducing the negative impacts of those facilities. These impacts include the use of valuable land, destruction of natural habitats, and aesthetic impacts, to name a few.

There are some potential negative impacts associated with energy efficiency measures. An example of a negative impact from conservation is the need to dispose of spent fluorescent light bulbs. Switching fuels will still have impacts associated with the use of the alternate fuel. Load management, if not designed properly, can lead to discomfort or the inefficient disruption of industrial production. However, the negative effects of energy efficiency measures are negligible compared to the building and operation of power plants and power lines.

The Commission's legal requirements regarding DSM as an alternative

Under Wis. Stat. § 196.491(3)(d)3, in order to approve the power lines proposed by the applicants, the Commission must find that the lines are "in the public interest considering alternative sources of supply…economic (factors)…and environmental factors." Energy efficiency, if it is available, can be considered an alternative source of supply, could lower costs, and would likely result in fewer environmental impacts.

Wis. Stat. § 196.025 declares: "To the extent cost-effective, technically feasible and environmentally sound, the Commission shall implement the priorities under s. 1.12(4) in making all energy-related decisions." Wis. Stat. § 1.12(4) creates the following priorities:

> (4) PRIORITIES. In meeting energy demands, the policy of the state is that, to the extent cost–effective and technically feasible, options be considered based on the following priorities, in the order listed:
> (a) Energy conservation and efficiency.
> (b) Noncombustible renewable energy resources.
> (c) Combustible renewable energy resources.
> (d) Nonrenewable combustible energy resources, in the order listed:
> 1. Natural gas.
> 2. Oil or coal with a sulphur content of less than 1 percent.
> 3. All other carbon–based fuels.

If the Commission finds, under these laws, that energy conservation or efficiency can substitute cost-effectively for the proposed power lines, the Commission's decision must ensure that the conservation is implemented. For the Commission to choose energy efficiency over the proposed power lines, the Commission must find: (1) that enough energy efficiency exists to substitute for all or part of the energy demand that would be served by the proposed power lines (if only part, then something else must provide the rest); (2) that conservation would be cost-effective compared to the alternative facilities for which it would be substituting; and (3) that the energy efficiency option is environmentally sound.

Changes occurring in the regulation of energy efficiency

During the past two decades, the Commission has relied upon regulated electric and natural gas utilities to promote energy efficiency. Utility DSM programs have largely been cost-effective and successful. It is estimated that from 1991 through 1998, Wisconsin utility programs reduced annual electricity usage by 3,526,000 MWh. This amount of energy is roughly equivalent to the annual output of a 500 MW coal plant.

However, the regulation of energy utilities is changing, and with it the regulatory approach to the promotion of conservation and other forms of energy efficiency. New legislation passed in the fall of 1999 is having a significant impact on how energy efficiency services are delivered – and by whom. Public utilities will soon have less responsibility for delivering conservation services.

A substantial amount of utility ratepayer dollars that, in the past, went toward utility-sponsored energy efficiency programs and services will be transferred to DOA. In addition to this existing funding, new fees for energy efficiency will be collected from utilities. DOA will be responsible for overseeing the promotion of energy efficiency through contracts with administrators that will bid competitively for delivery of conservation services. DOA must give priority to proposals directed at the energy efficiency market sectors that are least competitive, and at promoting environmental protection, electric system reliability, or rural economic development.

In addition to the DOA funding discussed above, the utilities will retain funds to be used for utility-administered, energy efficiency-related customer service activities. Because the Commission approved utility retention of some funds, the Commission will continue to have some authority over utility services and accomplishments. The Commission will ensure that utility funds are transferred to DOA, but will have no other authority over DOA actions.

Table 4-1 Annual budget for energy efficiency for the state of Wisconsin [71]

Component	Amount
Funds to DOA for conservation	$57,347,950
Funds to DOA for low-income weatherization	$8,503,500
Utility funds for internal programs	$24,587,100
Total	**$90,438,550**

This funding level is not as high as past years. Table 4-1 shows the total budge for energy efficiency programs in Wisconsin. These years of highest spending were the basis of the projected level of energy efficiency achievable that were approved in AP-8 and assumed in the forecasts that underlie the analyses in the Arrowhead-Weston application and this EIS. Those levels were based on continuation of the types of programs utilities were doing at the time. However, no one is conducting those same kinds of programs now. The new emphasis is on market transformation, a strategy to get the market to a place where energy efficiency will happen without direct intervention of the utilities or the state government. Therefore, it is not clear whether DOA/utility efforts will accomplish more or less than the AP-8 levels of energy efficiency that were assumed in the planning for this proposed line.

It is not yet clear how these changes will affect the Commission's responsibilities in evaluating energy conservation as an alternative to utility projects, and the Commission's statutory requirement to implement the conservation priority.

[71] This budget level does not include funds from the municipal and cooperative utilities. They are also required to collect a specified amount of funds from ratepayers but they have a choice of administering programs themselves or transferring the funds to DOA. These utilities have not made that choice yet.

Applicants' analysis of energy efficiency

The applicants originally announced their intent to build the proposed power lines in April 1999. On June 17, 1999, Commission staff informed the applicants of the need to provide an energy efficiency analysis in their application. The applicants were instructed to "use proxy calculations to determine if conservation alternatives might be cost-effective." The original filing, on November 10, 1999, contained an analysis of the energy efficiency alternative to the proposed Arrowhead-Weston line. The full text is included below. Applicants rejected energy efficiency as an alternative to the Arrowhead-Weston line because:

> Conservation measures, through demand side management (DSM) programs, are not reasonable alternatives to the Weston – Arrowhead project. DSM, through a process known as targeted area planning (TAP), is often employed to target a particular customer group within a defined geographical location to reduce the demand for electrical capacity and energy. The Weston – Arrowhead project is *required to restore adequate reliability and operating margins within a geographical region that encompasses several states*. DSM alternatives, requiring significant time to modify customer habits that ultimately lead to an ultimate reduction in demand in very defined customer groups, are not viable tools to address regional reliability and operational issues. Even if DSM was capable of reducing load growth within the entire Midwest to zero, additional transmission infrastructure across the western interface is required to re-establish and maintain reliability margins within the bulk power system. As previously mentioned, the existing western interface is continually encumbered with operating restrictions just to maintain security of the system which is increasingly burdened with non-traditional uses. The current reliability benefit of the western interface is near zero and the only viable option to restore the reliability benefit is to expand the capability of the interface.

(application, p. 49; emphasis added.) No economic analysis of the cost-effectiveness of energy efficiency was included in the original application. Commission staff identified this lack of analysis to the applicants on November 23, 1999. Subsequently, on December 7, 1999, the applicants provided supplemental analyses of the cost-effectiveness of energy efficiency. This analysis is provided in Appendix B of this EIS.

Applicants' feasibility analysis of energy efficiency (Arrowhead-Weston)

The applicants' original and supplemental feasibility analysis, as presented in the application and Appendix B, has several problems. The applicants state that the magnitude of the need, compared to available energy efficiency, means that "conservation is not a viable alternative." An "all-or-nothing" approach ignores the fact that energy efficiency may be able to contribute to a package of transmission, new generation, and energy efficiency to meet any need for additional capacity. The applicants also assumed that Wisconsin needs 750 MW of additional transfer capacity. The level of need is an issue in this proceeding.

The applicants' analysis relied in part on the applicants' interpretation of TAP proceedings during the past several years. The applicants state that the need for additional transmission capacity is driven by "bulk loads." The applicants noted that the TAP Collaborative concurred that projects driven by bulk loads are probably not amenable to TAP solutions, such as targeted DSM. Members of the TAP Collaborative agreed to apply the TAP analysis only to targeted local transmission needs, to evaluate distributed generation, locally sited renewable resources and targeted DSM. System planning was to be conducted by whatever rules would apply to system planning.

The Arrowhead-Weston line is proposed to address system reliability, not to provide capacity to a limited, targeted area. It therefore is not appropriate for TAP analysis. This does not mean, however, that system alternatives, such as wide-scale energy efficiency, are inappropriate to consider as alternatives to the proposed Arrowhead-Weston power line.

The applicants, in their supplemental analysis, calculated what they believe to be the cost of energy efficiency, expressed as a cost per MW. This number was calculated by dividing WPSC's 1998 total electric DSM spending of $5,103,070 by the 4.11 MW the utility expected to capture through its DSM programming. The result was $1,241,623 per MW. The cost per MW was then multiplied by the applicants' claimed need of 750 MW. At present value, the result was $738,826,710 for 750 MW of demand reduction. The applicants concluded that this cost should be compared to the cost of the Arrowhead-Weston power line.

The 1998 DSM costs that WPSC used to derive its energy efficiency cost estimates are not representative of the average cost of conservation or load management. In 1998, WPSC contracted with the DOA to deliver most of its DSM programming. WPSC transferred roughly $8 million to the DOA for 1998 and received credit for roughly 70 percent of its 1998 electric energy savings goal. The costs cited by the applicants represent the costs for activities that WPSC chose to retain in-house in 1998. These programs are not representative of best-practice, cost-effective energy efficiency programs. More importantly, the cited cost for these programs, $5,103,070, includes $3,589,020 (70 percent) in "level 4 costs." Level 4 costs represent general and administrative dollars not attributable to any specific program, or even to the programs for any specific customer sector.

The applicants' calculation of cost per MW also included the costs of conservation programs that were not primarily designed to capture peak demand savings. Conservation programs generally are designed to save energy cost-effectively, not to reduce peak demand. Load management programs and conservation programs targeted at peak energy use can usually capture demand savings at a lower cost per MW than other conservation programs.

The third, most significant, problem with the applicants' economic analysis was that energy efficiency was not given economic credit for avoided energy costs. To the extent that energy efficiency saves energy as well as demand, it must be credited with the costs of the energy generation that are avoided. If most utility efficiency programs are cost-effective just due to avoided energy costs (even without avoiding the costs of a major transmission line), then the net cost of those programs for also offsetting a transmission line is negative. By comparison, the applicants attributed no cost to the power and energy that would have to be generated and transmitted over the proposed power lines. At times of system peak, these costs could be significant. The cost to avoid generation and transmission should be higher than the cost to just avoid generation. If the avoided cost of both generation and transmission are taken into account, more could be spent per kilowatt hour (kWh) to capture more DSM and still be cost effective.

Commission staff analysis of energy efficiency

If a fundamental need for the Arrowhead-Weston project is to provide transfer capacity to supply the new competitive market, that is, to increase transmission capacity to enable all market players to purchase energy from wherever they wish – energy efficiency is not a feasible alternative. Energy efficiency cannot be designed to meet that kind of need. Energy efficiency can have a secondary benefit of opening up some transmission line capacity, but it cannot meet a need that is unknown. If Arrowhead-Weston is needed to provide regional reliability then the analysis of energy as an alternative should be a regional analysis and a regional commitment to implement the recommended energy efficiency measures. This kind of analysis and commitment requires resources beyond those available to the Commission.

If Arrowhead-Weston is needed to provide reliability in Wisconsin, specifically to eastern Wisconsin, then a new analysis of energy efficiency, similar to the Statewide Technical and Economic Potential (STEP)[72] analysis, should be done. A thorough analysis of this type would require resources beyond those currently available to the Commission. The STEP analysis, performed in recent Advance Plans, is becoming very outdated. The original STEP analysis was based on data pertinent to the types of efficiency programs offered by the utilities in the past. Those programs are no longer offered, and the Commission does not have similar data on current programs. The utilities paid for the original analysis, which was completed by a third party consultant and monitored by the utilities and Commission staff. This process typically took more than one year to complete.

A second-best approach would be to use the old STEP analysis to determine how much more energy efficiency could be implemented at a cost below the cost of the proposed line. This is the approach being taken by the consultant hired by WED. This will provide the best energy conservation information possible in view of the resource constraints and the time frame of this case.

Intervenor's analysis of energy efficiency

WED, an intervenor with party status in this docket, has hired a consultant to address the issue of the potential for energy efficiency as an alternative to the proposed power line. The Commission staff is working with the intervenors and the applicants to produce a hearing record that will be adequate for the Commission to evaluate energy efficiency as an alternative to the

[72] The STEP analysis is described in the May 1995 PSCW document Recalculation of Statewide Technical and Economic Potential (Revised Document D-12) from Advance Plan 7.

proposed transmission project. The Commission staff will review and comment on any analysis performed by WED and other parties during the hearings in this docket.

Long-term implications of energy efficiency policy changes

It is not yet clear how the described policy changes will affect the Commission's responsibilities in evaluating energy efficiency as an alternative to utility projects, and the Commission's requirement to implement the state energy priorities. This evaluation is even more uncertain for projects based on regional need or on competitive market needs.

The Commission has no authority to change regional energy efficiency activities. Some would consider it inappropriate to order Wisconsin utilities to spend money to accomplish regional DSM. They would also argue that if the Commission were to order Wisconsin utilities to spend more on just Wisconsin DSM, there is no assurance that the other regional Commissions or utilities would follow suit, and if they did not, Wisconsin utilities could be put at a competitive disadvantage.

Market-based curtailable load programs

During 2000, in response to provisions of 1999 Wisconsin Act 9, the Commission approved new electric rate tariffs that will enhance reliability. In April 2000, the Commission approved the ability of public utilities to enter into individual contracts with customers. In addition, in May 2000, the Commission approved load reduction tariffs which allow a customer to curtail firm load in exchange for market-based compensation. This new program would have the effect of reducing peak electric demand during times of high system stress and could be an alternative to the construction of a major new transmission line. Unfortunately, due to the untried nature of the voluntary firm load curtailment program, there are no reliable estimates of the potential level of participation, the size of any potential reduction in firm peak demand, or the cost of the program.

Real-time pricing

Another alternative that can curtail load is to implement real-time pricing (RTP) for large industrial and commercial customers.[73] RTP, a form of peak load pricing, refers to the practice of charging for electricity at a tariff rate corresponding to a particular hour's marginal cost of production. For instance, if the marginal cost of producing electricity at 1 p.m. is $0.09/kWh, then the customer pays $0.09/kWh. At night when the marginal cost of producing electricity at 1 a.m. is $0.02/kWh, then the customer pays $0.02/kWh. This is in contrast to the present rate situation in Wisconsin in which numerous industrial and commercial customers pay a flat

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[73] RTP is generally only offered to commercial and industrial customers, because of the ability of some of these customers to monitor prices on a daily or hourly basis and to significantly modify their demand in response to these prices. There are several tariff methods that can be used to implement real-time pricing. Such methods are not discussed here. Instead, the overall concept of RTP is evaluated.

$0.0386/kWh and $0.0587/kWh respectively, regardless of the hour that the electricity is used.[74] By implementing RTP, industrial and commercial customers face the real cost of producing electricity. This form of price signaling provides a strong incentive for a customer to reduce demand when hourly electricity prices are high, and conversely, increase demand when hourly electricity prices are low. Reducing demand during peak periods of electricity use represents a load reduction that can directly translate into reduced needs for new generation and transmission facilities.

Whether or not a full-scale implementation of RTP can offset the need for the Arrowhead-Weston transmission facilities can be determined by examining industry practice outside of Wisconsin. This is necessary, because present state practice uses only limited forms of RTP, such as time-of-use or seasonal electricity rates.

Presently, Georgia Power Company operates the largest RTP program in the United States. Georgia Power's RTP program covers over 1,000 companies, representing 20 percent of the utility's system peak. Current estimates are that the Georgia Power's RTP program reduces peak load from large customers by 5 to 10 percent when real-time electricity prices are between 5 and 10 cents per kWh. The response is greater than a 10 percent load reduction when the real-time price rises to 25 cents per kWh.[75] Overall, the use of RTP has reduced Georgia Power's system peak between one and two percent.[76]

In 1995, Christensen Associates and the Electric Power Research Institute (EPRI) produced the study, "Reaping the Benefits of Real-time Pricing, Georgia Power's RTP Evaluation Case Study." This study examined individual firms' behavior under Georgia Power's RTP program. The study concluded that the RTP program for Georgia Power's curtailable and interruptible large customers resulted in an additional 10 to 15 percent load reduction.[77]

In California, Pacific Gas and Electric Company (PG&E) has also operated an RTP program since 1994. PG&E reports that its RTP program has reduced participants' load by 12 percent.[78] Southern California Edison's RTP produced a smaller 5 percent reduction in load for large

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[74] These values are statewide averages and are from the US DOE EIA publication, Electric Sales and Revenue 1998. Some industrial and commercial customers do face time-of-day rates, which are a form of peak load pricing.

[75] This information can be found in "Real-time Pricing," by Hansor, Wharton, and Fox-Penner, Public Utilities Fortnightly, March 1, 1997.

[76] Calculated as 20 percent times the range of 5 percent to 10 percent.

[77] Page 2-6, Reaping the Benefits of RTP, Georgia Power's RTP Evaluation Case Study, Volumes 1 and 2, prepared for Electric Power Research Institute, Palo Alto, California, by Christensen Associates, Madison, Wisconsin, December 1995.

[78] Findings reported in PG&E's Real-Time Pricing Program, 1995 Annual Report.

customers, over a broad number of high electricity price hours.[79] Finally, an academic review of the load reduction results from RTP programs in the U.S. found that electricity bills could decline up to 20 percent.[80] In light of these findings, the potential load reduction for participating large industrial and commercial customers available from a full-scale implementation of RTP appears to be 5 to 20 percent. For purposes of this EIS, PG&E's 12 percent reduction result is used because it is an actual result in the middle of the identified range.

In order to gauge the potential for RTP programs in Wisconsin to reduce load, an analysis of demand is necessary. In summer 1999, the state's utilities experienced 10,761 MW of peak demand (excluding interruptible customers). The Georgia Power experience suggests that an aggressive RTP program can capture up to 20 percent of statewide system load. In Wisconsin, that would mean that up to 2,152 MW of load could be placed in a Wisconsin RTP program. Since the average reduction in load from RTP programs appears to be around 12 percent, the implementation of RTP in Wisconsin could shave 258 MW.[81]

A load reduction level of 258 MW is no match for the 2,200 MW of import capability the proposed Arrowhead-Weston line would create. Consequently, RTP by itself is not a viable alternative. It could, however, be used as part of a larger package of alternatives.

Generation Alternatives to the Arrowhead-Weston Line

Cost calculations for 1,560 MW of reliability enhancement using conventional generation sources

Background

In this section, the cost of new generation is compared to the cost of the Arrowhead-Weston Transmission Project. New generation either from rate-based electric utility projects or IPP wholesale merchant plants in Wisconsin can be a substitute for the construction of new transmission facilities, although more often than not generation and transmission facilities are complements to one another. Generally, new generation supply cannot be substituted for transmission on a one-for-one MW basis. This is because generation has a relatively high outage

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79 Page IV-23, Fielding a Real-Time Pricing Program, Pennsylvania Power and Light Case Study, prepared for Electric Power Research Institute, Palo Alto, California, by Christensen Associates, Madison, Wisconsin, August 1995.

80 "Efficient Load-Management Tools in Competitive Electricity Markets: Time-of-Use Rates," Orasch, Haas, and Huber, Institut fur Energiewirtschaft, Vienna University of Technology, Vienna, Austria, at internet address http://extranet.ctech.ac.za./ctech/techconf

81 If the whole state load in Wisconsin could be made to participate, then the 12 percent PG&E type of reduction would mean that Wisconsin's system peak could be reduced by 1,076 MW. Using such an estimate is, however, fraught with error since it requires a statistical extrapolation outside the range of the 20 percent sample.

rate compared to transmission lines. For example, a transmission line may be available to deliver power 99 percent of the time, whereas the availability of a combustion turbine generator ranges from 86 to 91 percent, depending on the unit size. Due to this engineering characteristic, up to 26 percent more megawatts of generation may be needed to offset the need for a certain level of transmission import capability.

The Arrowhead-Weston application provides an LOLE analysis that allows an even more specific calculation.[82] Basically, two reliability situations are compared in the application. The first is a scenario where generation is added so as to maintain an eastern Wisconsin reserve margin of 18 percent. This amounts to 1,560 MW through 2007. In this case the amount of imported capacity required to ensure that an LOLE of 0.1 day/year can be achieved is comparable to the import capability of the existing system. The second situation, on the other hand, maintains reliability by importing additional capacity but constructing no additional electric generation. In this second situation, the application's LOLE analysis shows that the cumulative amount of imported capacity needed by 2007 is approximately 1,470 MW more than if an 18 percent generation reserve margin is required. Combining these results indicates that from a reliability perspective, 1,560 MW of new electric generation is roughly equivalent to 1,470 MW of new transfer capability and power purchases associated with the new transmission line. This means that roughly six percent more generation is needed for reliability purposes as compared to transmission transfer capability. The view that 1,560 MW of generation is equal to 1,470 MW of power purchases using a new transmission line is termed the "LOLE reliability perspective" in discussions below.

In contrast, the applicants' cost analysis is based on a different set of assumptions. The applicants' analysis assumes that even if the proposed project were built, generation would be added in eastern Wisconsin at a rate that would roughly keep pace with growth in electricity demand, and that the incremental generation required by 2007 in the absence of a major new line would be just over 800 MW. This corresponds to assuming that the EWU would continue to rely on roughly the same level of imports from outside of Wisconsin as they do today, rather than increasing this reliance as the LOLE reliability perspective would do. The applicants' approach is termed a "pure capacity reliability" perspective in discussions below.

Some insight into the question of how much additional generation capacity outside of Wisconsin will be available for purchase can be gained by examining current power plant use and planned future construction in the MAPP region. This question is addressed later in this chapter. Nonetheless, it is not possible to predict exactly how a new line would be used by Wisconsin utilities, and the corresponding degree to which they would rely on power purchased from elsewhere rather than on local generation. These two sets of assumptions define two distinct reliability scenarios for future generation expansion if no new line is built. In the first case or LOLE reliability perspective, 1,560 MW of new generation is added to eastern Wisconsin through 2007, which would be enough for eastern Wisconsin utilities to meet their 18 percent reserve margin requirement entirely from generation internal to eastern Wisconsin. According

[82] See Arrowhead to Weston application, Volume 1, page 43, Tables 5 and 6.

to the pure capacity reliability perspective, a smaller amount of incremental generation would be added, such that the utilities' collective reserve margin would include roughly the same amount of purchases from outside eastern Wisconsin as is true today. These two scenarios represent the upper and lower boundaries of assumptions to use in an analysis of costs. The first of these scenarios is considered in the next section, and the second in later sections of this chapter.

Cost calculations

Turning to the comparative cost analysis, Commission engineering staff estimates that the high-end construction cost for the Arrowhead-Weston Transmission Project is $222 million.[83] This is in contrast to the original application for the Arrowhead-Weston line indicating a construction cost of $250 million, the value used in the draft EIS.[84] Based on a $222 million total construction cost, the real levelized annual capital charge for the Arrowhead-Weston Transmission Project that ratepayers would face is $19.33 million per year in 1999 dollars. This annual value is calculated using a conventional revenue requirement model.[85]

Presently, around the country there is active industry development of both combustion turbines and combined-cycle generating units. The following cost analysis examines the displacement of 1,470 MW of import transfer capability and purchase power associated with the Arrowhead-Weston line with 1,560 MW of new electrical generation in the form of either combustion turbines or combined cycle units. The cost estimates are for rate-based electric utility projects, but in this EIS such estimates are also proxies for electric power costs from IPP wholesale merchant plants. In terms of operation, combustion turbines are ordinarily used for peaking duty. In the following analysis, peaking duty is assumed to mean 850 hours of dispatch with most occurring during summer months. In comparison, combined-cycle units are ordinarily used for intermediate duty. In the following analysis, intermediate duty is assumed to mean 3,400 hours of annual operation, which represents a 39 percent capacity factor.

In AP-8 the least expensive peaking duty generation project in terms of capital cost is a combustion turbine. AP-8 data show that the ordinary construction cost of a peaking-duty combustion turbine is $293 per kilowatt (kW) in 1999 dollars when multiple units are constructed. The total construction cost of 1,560 MW of peaking-duty generating capacity would be $457 million.

In AP-8 the least expensive intermediate-duty generation project in terms of capital cost is a combined-cycle unit. AP-8 data show that the ordinary construction cost of an intermediate-

[83] This $222 million estimate is comprised of $203 million for the construction of the Arrowhead-Weston line developed in Chapter 1 and $19 million in other system improvements necessary to achieve the application's stated import transfer capability.

[84] It should be noted that in April 2000, WPSC submitted an addendum indicating that the construction cost for the Arrowhead-Weston Transmission Project was actually $203 million.

[85] Key parametric assumptions include a 40 year book life, 20 year tax life, 5.5 percent real discount rate, 3 percent general inflation rate, and a 9.95 percent weighted cost of capital.

duty combined-cycle generating unit is $526 per kW in 1999 dollars when multiple units are constructed.[86] The total cost for the construction of 1,560 MW of intermediate-duty generating capacity would be $821 million.

In order to compare generation and transmission alternatives for cost effectiveness, the annual impact on rates must be analyzed. Table 4-2 and Table 4-3 present the annual ratepayer and customer impact in 1999 dollars of using either 1,560 MW of combustion turbine or combined-cycle generation versus 1,470 MW of transmission line energy imports at wholesale market prices, to meet Wisconsin's reliability-associated electricity needs. The analysis in Table 4-2 and Table 4-3 is based on the following:

- The real levelized annual capital charge for a combustion turbine generating unit is $21.80 per kW. This value is calculated using a conventional revenue-requirement model. Parameter estimates in the model were the same as those used for the Arrowhead-Weston line except that a 15-year tax life was used. This tax life assumption has the effect of slightly lowering the cost of combustion turbines versus other options.
- The real levelized annual capital charge for a combined-cycle generating unit is $44.38 per kW. This value is calculated using a conventional revenue-requirement model. Parameter estimates in the model were the same as those used for the Arrowhead-Weston line.
- The marginal operation or energy cost of a combustion turbine is $32.80 per MWh based on the AP-8 estimate of a full-load heat rate of 11,133 BTU per kWh, $2.86 per million British Thermal Units (MBTU) for natural gas, and $0.96 per MWh for variable operations and maintenance (O&M) of a combustion turbine.[87]
- The marginal operation or energy cost of a combined-cycle unit is $19.66 per MWh based on the AP-8 estimate of a full load heat rate of 7,454 BTU per kWh, $2.59 per MBTU for natural gas, and $0.36 per MWh for variable O&M of a combined-cycle generating unit.[88]
- Based on AP-8 estimates, fixed O&M for combustion turbines is $2.50 per kW and for combined-cycle units $15.13 per kW.
- Power purchase prices in the first Arrowhead-Weston line cost scenario replicate the actual system power purchase practices of the state's five largest investor owned electric utilities in 1999. According to FERC Form 1 Account 555 data, the average energy purchase price in Wisconsin was $24.11 per MWh in 1999. In terms of

[86] AP-8 values were in 1997 dollars. In this final EIS, two years of 3 percent annual inflation are added to derive 1999 dollars.

[87] The actual calculation is [(11,133*2.86)/1000] +[$0.96] = $32.80 MWh.

[88] The actual calculation is [(7454*2.59)/1000] +[$0.36] = $19.66 MWh.

capacity charges, it is assumed that 1,470 MW of combustion turbine capacity provide the firm supply backup. This requires a proxy capacity charge of $32 million.[89]

- Power purchase prices in the second Arrowhead-Weston line cost scenario are assumed to follow the market pattern displayed from June 1998 to May 1999.[90] According to Bloomberg, the median day-ahead spot-market price for firm daily peak energy in MAIN was $32.50 per MWh from June 1 to September 15, 1998; $21.50 per MWh September 16, 1998, to December 15, 1998; $19.89 per MWh December 16, 1998, to March 31, 1999; and $25.59 per MWh April 1 to May 1999.[91] In addition to these energy prices, a separate demand or proxy capacity charge equivalent to 28.3 percent of the total energy charge is assessed up to the $32 million ceiling charge for 1,470 MW of firm combustion turbine capacity.[92]

- The Midwest ISO is in place, and energy purchases are from Midwest ISO members. This means that the comparative transmission rate in the cost analysis drops to zero as each of the options in Tables 4-2 and Table 4-3 would face the same tariff. Under the Midwest ISO, the transmission tariff for a purchase is based on the location of the load being served.

- Arrowhead-Weston line annual maintenance costs are $350,000. This value is based on 250 miles of line at $1,400 per mile. This per mile estimate is based on WEPCO's actual experience in 1999 maintaining 499 miles of existing 345 kV transmission line.

- The analysis uses the following comparative net energy credits for reducing losses on the overall transmission system due to the presence of the Arrowhead-Weston Transmission Project relative to using conventional generation: For peaking duty, the comparative net energy credit is $3.3 million and is comprised of 1 MW of savings at $30 per MWh for 850 hours when the combustion turbine generation would be running and 21 MW of savings at $20 per MWh for the remaining 7,910 hours. For intermediate duty, the comparative net energy credit is $2.4 million and is comprised of 1 MW of savings at $30 per MWh for 3,400 hours when combined-

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[89] The $32 million capacity charge is calculated using 1,470 MW times a $21.80 per kW cost for combustion turbine capacity. By using such a ceiling capacity charge, the first method analysis becomes akin to a "peaker method" avoided cost methodology. See Commission docket 05-EI-112, December 28, 1993.

[90] These prices exclude price spikes as discussed in Chapter 2. In this way the prices reported here are proxies for more normal market pricing conditions. In addition, Summer and Fall 1998 prices are used here for the analysis to be on the conservative side as the 1999 equivalent MAIN prices were lower at $29.84 and $20.59 per MWh respectively than the 1998 values.

[91] Power prices are for firm on-peak power with liquidated damages.

[92] The 28.3 percent value is from 1999 Wisconsin historical experience for energy purchases requiring a demand charge as reported by WEPCO, WPS, and MG&E in their annual reports to the Commission. By using this convention, the second cost method is meant to approximate utility practice.

cycle generation would be running and 21 MW of savings at $20 per MWh for the remaining 5,360 hours.[93]

The analysis in Table 4-2 shows that the annual operating cost of combustion turbines and combined-cycle units for peaking duty is between $79 and $117 million, while importing power using the transmission grid would cost between $62 and $78 million on an annual basis. This range represents a cost savings of between 1 and 22 percent in favor of the line over the construction of conventional electric generation. This relationship is portrayed in Figure 4-2.

The above cost analysis assumes no Arrowhead-Weston project cost overruns and that 1,470 MW of capacity and energy would be available for purchase. In addition, estimates do not include the option value or credit of having a new transmission line available during off-peak periods to purchase potentially lower cost energy than that available without such a line. With this consideration in mind, the use of peaking duty combustion turbine or combined-cycle capacity to displace the Arrowhead-Weston Transmission Project and associated power purchases at current market prices is likely not a cost-effective alternative.[94] This conclusion is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs.[95]

The analysis in Table 4-3 shows that the annual operating cost of combustion turbines and combined-cycle units for intermediate duty is between $191 and $202 million, while importing power using the transmission grid would cost between $170 and $176 million on an annual basis. This represents a cost savings of about 10 percent in favor of the line over the construction of conventional electric generation. This relationship is portrayed in Figure 4-2. Consequently, the use of intermediate combustion turbine or combined cycle capacity to displace the Arrowhead-Weston Transmission Project and associated power purchases at current market prices is likely not a cost-effective alternative.[96] This conclusion is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs. The analysis also assumes no Arrowhead-Weston project cost overruns and that 1,470 MW of capacity and energy would be available for purchase. In addition, estimates do not include the option value or credit of having a new transmission line available during off-peak periods to purchase potentially lower cost energy than that available without such a line.

[93] For comparison, the WIRE study used an estimate of 380,000 MWh. At $20 per MWh, the WIRE study's energy loss credit would be $7.6 million; and at $30 per MWh, it would be $11.4 million. Commission staff engineers have recalculated the appropriate values here.

[94] This result slightly weakens when long-run 2010 purchase power prices are examined in a later sensitivity.

[95] Externality costs refer to the societal costs of unwanted and improperly controlled pollution for instance.

[96] This result weakens when long-run 2010 purchase power prices are examined in a later sensitivity. With 2010 purchase power prices, there is no clear advantage for the transmission line project and imported power as compared to constructing intermediate duty combined cycle generation.

Table 4-2 Peaking-duty comparison of conventional generation and transmission project costs using current purchased power prices

LOLE Reliability Perspective--Peaking Duty 1999 Dollars	Item	AP-8 CT Generation	AP-8 CC Generation	Method 1 A-W Project Avg .Purchase Power Prices	Method 2 A-W Project Bloomberg Power Prices
Capital cost $/kW		$293	$526		
Capacity equivalence MW		1,560	1,560	1,470	1,470
Total construction cost (millions)		$457.1	$820.6	$222.4	$222.4
Levelized annual charge $/kW		$21.80	$44.38	NM	NM
Yearly capital cost (millions)	A	$34.0	$69.2	$19.3	$19.3
Capacity charge (millions)	B	$0.0	$0.0	$32.0	$10.0
Fixed O&M (millions)	C	$4.1	$23.6	$0.4	$0.4
Summer energy price $/MWh		$32.80	$19.66	$24.11	$32.50
Hours of summer duty		475	475	475	475
Summer energy cost @ 1470 MW (millions)	D	$22.9	$13.7	$16.8	$22.7
Fall energy price $/MWh		$32.80	$19.66	$24.11	$21.50
Hours of fall duty		150	150	150	150
Fall energy cost @ 1470 MW (millions)	E	$7.2	$4.3	$5.3	$4.7
Winter energy price $/MWh		$32.80	$19.66	$24.11	$19.89
Hours of winter duty		75	75	75	75
Winter energy cost @ 1470 MW (millions)	F	$3.6	$2.2	$2.7	$2.2
Spring energy price $/MWh		$32.80	$19.66	$24.11	$25.59
Hours of spring duty		150	150	150	150
Spring energy cost @ 1470 MW (millions)	G	$7.2	$4.3	$5.3	$5.6
1999 annual capacity & energy cost (millions)	H	$79.1	$117.4	$81.8	$64.9
Energy credit for reducing losses on system (millions)	I			$3.3	$3.3
Total costs (millions)	J	$79.1	$117.4	$78.4	$61.6
H=A+B…G					
J=H-I					

Table 4-3 Intermediate-duty comparison of conventional generation and transmission project costs using current purchase power prices

LOLE Reliability Perspective--Intermediate Duty 1999 Dollars	Item	AP-8 CT Generation	AP-8 CC Generation	Method 1 A-W Project Avg. Purchase Power Prices	Method 2 A-W Project Bloomberg Power Prices
Capital cost $/kW		$293	$526		
Capacity equivalence MW		1,560	1,560	1,470	1,470
Total construction cost (millions)		$457.1	$820.6	$222.4	$222.4
Levelized annual charge $/kW		$21.80	$44.38	NM	NM
Yearly capital cost (millions)	A	$34.0	$69.2	$19.3	$19.3
Capacity charge (millions)	B	$0.0	$0.0	$32.0	$32.0
Fixed O&M (millions)	C	$3.9	$23.6	$0.4	$0.4
Summer energy price $/MWh		$32.80	$19.66	$24.11	$32.50
Hours of summer duty		1000	1000	1000	1000
Summer energy cost @ 1470 MW (millions)	D	$48.2	$28.9	$35.4	$47.8
Fall energy price $/MWh		$32.80	$19.66	$24.11	$21.50
Hours of fall duty		800	800	800	800
Fall energy cost @ 1470 MW (millions)	E	$38.6	$23.1	$28.4	$25.3
Winter energy price $/MWh		$32.80	$19.66	$24.11	$19.89
Hours of winter duty		800	800	800	800
Winter energy cost @ 1470 MW (millions)	F	$38.6	$23.1	$28.4	$23.4
Spring energy price $/MWh		$32.80	$19.66	$24.11	$25.59
Hours of spring duty		800	800	800	800
Spring energy cost @ 1470 MW (millions)	G	$38.6	$23.1	$28.4	$30.1
1999 annual capacity & energy cost (millions)	H	$201.8	$191.1	$172.2	$178.2
Energy credit for reducing losses on system (million)	I			$2.4	$2.4
Total costs (millions)	J	$201.8	$191.1	$169.8	$175.8
H=A+B…G					
J=H-I					

Figure 4-1 Annual cost to electricity customers for 1,470 MW of peaking-duty service using current purchase power costs

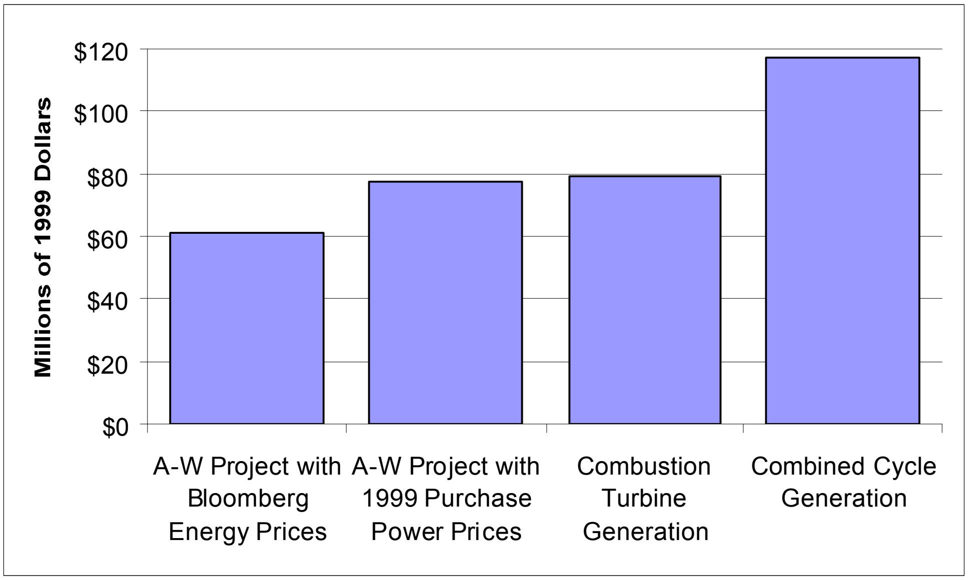
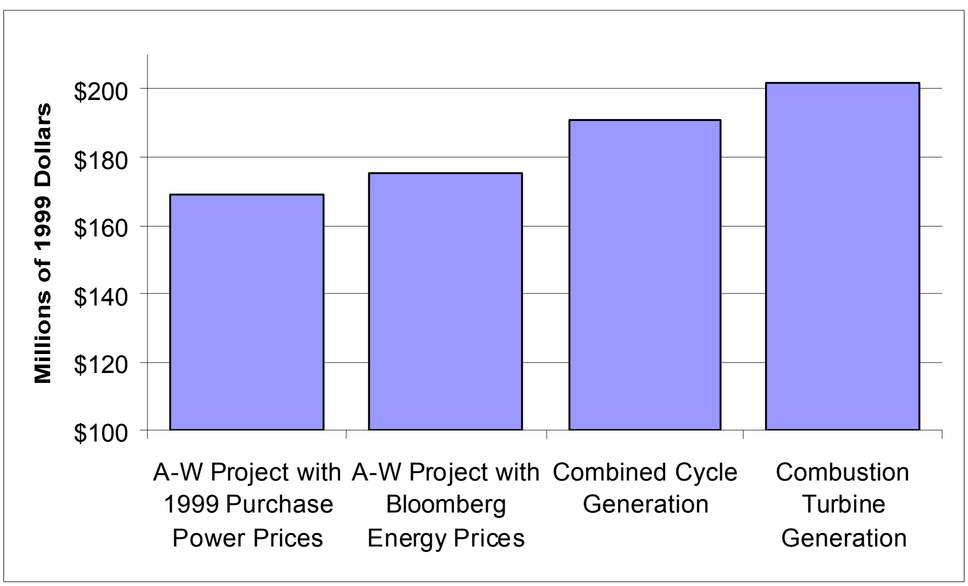


Figure 4-2 Annual cost to electricity customers for 1,470 MW of intermediate-duty service using current purchase power costs



Sensitivity of results to MAPP purchase power prices

The above cost analysis focused on energy prices in the MAIN reliability region. This section examines the above results using purchase power prices from the MAPP reliability region. In summary, use of purchase power prices from MAPP does not alter the above conclusion with respect to the relative cost effectiveness of the Arrowhead-Weston Transmission Project as compared to conventional electric generation.

According to Bloomberg, the median day-ahead spot-market price for daily peak energy in MAPP was $30.79 per MWh June 1 to September 15, 1998; $22.00 per MWh September 16, 1998, to December 15, 1998; $19.67 per MWh December 16, 1998, to March 31, 1999; and $25.17 per MWh April 1 to May 1999. With the exception of the fall energy price, the MAPP energy prices are slightly less than those in MAIN. When these MAPP energy prices are substituted into Table 4-2, the total cost of the Arrowhead-Weston line with power imported from MAPP becomes $60.0 million. This MAPP result is $1.6 million less than the peaking-duty scenario in Table 4-2 using MAIN power prices. Similarly, when these MAPP energy prices are substituted into Table 4-3, the total cost of the Arrowhead-Weston line with power imported from MAPP becomes $173.2 million. This MAPP result is $2.6 million less than the intermediate-duty scenario in Table 4-3 using MAIN power prices.

Sensitivity of results to expected 2010 purchase power prices

The above cost analyses focused on energy and capacity prices from current electric power markets. The following analysis examines the cost effectiveness of the Arrowhead-Weston project using a long-run forecast of MAIN and MAPP purchase power prices. Table 4-4 provides a forecast of expected purchase power prices in MAIN and MAPP for the year 2010. The forecast is from Resource Data International, Inc. (RDI) and is used by permission.[97] The forecast for the MAIN area is centered on WEPCO's control area. The forecast for the MAPP area is centered on NSP's control area. In addition, one set of forecast prices represents a purchase power energy price including a capacity charge, and the other set represents an on-peak energy price alone. At the end of the Table 4-4 are the all hours average energy price in annualized terms.

[97] RDI's Outlook for Power in North America-1999. Prices are expressed in 1999 dollars.

Table 4-4 RDI's expected year 2010 MAIN and MAPP purchase power prices in 1999 dollars

	MAIN Capacity And Peak Energy Price	MAPP Capacity And Peak Energy Price	MAIN On-Peak Energy Price Only	MAPP On-Peak Energy Price Only
Summer	$75.66	$76.49	$37.44	$31.83
Fall	$31.47	$31.38	$31.47	$31.30
Winter	$35.63	$34.61	$35.62	$34.61
Spring	$41.67	$31.22	$31.01	$27.31
$26.36	MAIN All Hours Average Price			
$23.66	MAPP All Hours Average Price			

Table 4-5 replicates the peaking-duty cost analysis in Table 4-2, except RDI's 2010 price forecast is used instead. There is also an important difference due to the way RDI forecasts future energy prices. In Table 4-5 a separate capacity charge, similar to that in Table 4-2, is assessed for the first two cost methods where the RDI energy price alone is used. However, in the situation where RDI does forecast a capacity charge as part of the purchase power price, then no additional capacity charge is assessed. This new characterization is listed as a third cost method in Table 4-5. Similar to previous cost analyses, 850 hours of operation represent a peaking-duty scenario; in terms of purchase power, 1,470 MW are required.

Table 4-5 indicates that the total cost of the Arrowhead-Weston project in combination with RDI's forecast electricity prices for the year 2010 and the import of 1,470 MW of power would be between $66 and $89 million for peaking-duty operation. This range compares to the $79 million estimate for the construction and operation of combustion turbines. Although there is some potential to be more expensive under the third cost method analysis, where RDI includes an estimated capacity charge in the energy price, estimates in Table 4-5 do not include the option value of having a new transmission line available during off-peak periods to purchase potentially lower cost energy than that available without such a line. This potential would translate into an additional credit in Table 4-5. The method used here does not allow an estimate of that credit. With this consideration in mind, this long-term sensitivity result suggests, for peaking duty operation, that construction of the Arrowhead-Weston Transmission Project and the import of electric power could be a cost-effective option. This conclusion is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs. The analysis also assumes no Arrowhead-Weston project cost overruns and that 1,470 MW of capacity and energy would be available.

Table 4-5 **Peaking-duty analysis of the Arrowhead-Weston transmission project's cost when RDI's 2010 purchase power forecast is used**

LOLE Reliability Perspective--Peaking Duty **1999 Dollars**	**Item**	**Method 1 MAIN** **RDI 2010 Average Purchase Power Prices**	**Method 2 MAIN** **RDI 2010** **On-Peak Power Prices**	**Method 3 MAIN** **RDI 2010 Energy and Cap Power Prices**	**Method 1 MAPP** **RDI 2010 Average Purchase Power Prices**	**Method 2 MAPP** **RDI 2010** **On-Peak Power Prices**	**Method 3 MAPP** **RDI 2010 Energy and Cap Power Prices**
Capital cost $/KW							
Capacity equivalence MW		1,470	1,470	1,470	1,470	1,470	1,470
Total construction cost (millions)		$222.4	$222.4	$222.4	$222.4	$222.4	$222.4
Yearly capital cost (millions)	A	$19.3	$19.3	$19.3	$19.3	$19.3	$19.3
Additional capacity charge (millions)	B	$32.0	$12.4	$0.0	$32.0	$11.0	$0.0
Fixed O&M (millions)	C	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Summer energy price $/MWH		$26.36	$37.44	$75.66	$23.66	$31.83	$76.49
Hours of summer duty		475	475	475	475	475	475
Summer energy cost @ 1470 MW (millions)	D	$18.4	$26.1	$52.8	$16.5	$22.2	$53.4
Fall energy price $/MWH		$26.36	$31.47	$31.47	$23.66	$31.30	$31.38
Hours of fall duty		150	150	150	150	150	150
Fall energy cost @ 1470 MW (millions)	E	$5.8	$6.9	$6.9	$5.2	$6.9	$6.9
Winter energy price $/MWH		$26.36	$35.62	$35.63	$23.66	$34.61	$34.61
Hours of winter duty		75	75	75	75	75	75
Winter energy cost @ 1470 MW (millions)	F	$2.9	$3.9	$3.9	$2.6	$3.8	$3.8
Spring energy price $/MWH		$26.36	$31.01	$41.67	$23.66	$27.31	$31.22
Hours of spring duty		150	150	150	150	150	150
Spring energy cost @ 1470 MW (millions)	G	$5.8	$6.8	$9.2	$5.2	$6.0	$6.9
1999 annual capacity & energy cost (millions)	H	$84.5	$75.9	$92.5	$81.2	$69.6	$90.6
Energy credit for reducing losses on system (million)	I	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3
Total costs (millions)	J	$81.2	$72.5	$89.1	$77.8	$66.2	$87.3
H=A+B…G							
J=H-I							

Table 4-6 Intermediate-duty analysis of the Arrowhead-Weston transmission project's cost when RDI's 2010 purchase power forecast is used

LOLE Reliability Perspective--Intermediate Duty 1999 Dollars	Item	Method 1 MAIN RDI 2010 Avg. Purchase Power Prices	Method 2 MAIN RDI 2010 On-Peak Power Prices	Method 1 MAPP RDI 2010 Avg. Purchase Power Prices	Method 2 MAPP RDI 2010 On-Peak Power Prices
Capital cost $/KW					
Capacity equivalence MW		1,470	1,470	1,470	1,470
Total construction cost (millions)		$222.4	$222.4	$222.4	$222.4
Yearly capital cost (millions)	A	$19.3	$19.3	$19.3	$19.3
Additional capacity charge (millions)	B	$32.0	$32.0	$32.0	$32.0
Fixed O&M (millions)	C	$0.3	$0.3	$0.3	$0.3
Summer energy price $/MWh		$26.36	$37.44	$23.66	$31.83
Hours of summer duty		1000	1000	1000	1000
Summer energy cost @ 1470 MW (millions)	D	$38.7	$55.0	$34.8	$46.8
Fall energy price $/MWH		$26.36	$31.47	$23.66	$31.30
Hours of fall duty		800	800	800	800
Fall energy cost @ 1470 MW (millions)	E	$31.0	$37.0	$27.8	$36.8
Winter energy price $/MWh		$26.36	$35.62	$23.66	$34.61
Hours of winter duty		800	800	800	800
Winter energy cost @ 1470 MW (millions)	F	$31.0	$41.9	$27.8	$40.7
Spring energy price $/MWH		$26.36	$31.01	$23.66	$27.31
Hours of spring duty		800	800	800	800
Spring energy cost @ 1470 MW (millions)	G	$31.0	$36.5	$27.8	$32.1
1999 annual capacity & energy cost (millions)	H	$183.3	$222.0	$169.9	$208.0
Energy credit for reducing losses on system (millions)	I	$2.4	$2.4	$2.4	$2.4
Total costs (millions)	J	$181.0	$219.6	$167.5	$205.7
H=A+B…G					
J=H-I					

Table 4-6 replicates the intermediate-duty cost analysis in Table 4-3, except RDI's 2010 price forecast is used instead. In Table 4-6 a separate capacity charge, similar to that in Table 4-3, is assessed. Similar to previous cost analyses, 3,400 hours of operation represent an intermediate-duty scenario; and in terms of purchase power, 1,470 MW are required.

Table 4-6 indicates that the total cost of the Arrowhead-Weston project in combination with RDI's forecast electricity prices for the year 2010 and the import of 1,470 MW of power would be between $168 and $220 million for intermediate-duty operation. This range of values indicates a modest potential for construction of the Arrowhead-Weston Transmission Project and the import of electric power to be a cost-effective option for intermediate duty operation. This is because the total cost of utilizing combined cycle generation for intermediate duty was estimated earlier at $191 million. However, the high end of the range also warns of the potential for the opposite result, namely that construction of the Arrowhead-Weston Transmission Project and the use of 1,470 MW of purchased power for long-term intermediate duty use may be an inferior option. These conclusions are based on what could occur in direct costs that affect electric rates; they do not factor in externality costs. The analysis also assumes no Arrowhead-Weston project cost overruns and that 1,470 MW of capacity and energy would be available. In addition, estimates do not include the option value or credit of having a new transmission line available during off-peak periods to purchase potentially lower cost energy than that available without such a line.

Sensitivity of results to current year 2000 economic considerations

Results in the above cost analyses are benchmarked to economic conditions in the 1997 to 1999 time frame. This is the case for power prices, fuel costs, generation and transmission line construction costs, capital costs, as well as all operations and maintenance costs. Such treatment facilitates a consistent economic comparison among the alternatives. However, circumstances in the year 2000 have in some cases significantly departed from the 1997 to 1999 experience.

Since April 2000 natural gas prices have increased from the AP-8 range of $2.59 to $2.86 per MBTU and have gone as high as $5.00 per MBTU. The consequence of this relatively large fuel price movement, if sustained, would be: (1) to increase the marginal energy costs of both the combustion turbine and combined cycle units, and (2) to place upward pressure on purchase power costs. It is unclear how these two price changes in the same direction would affect the peaking-duty conclusion that the Arrowhead-Weston project is potentially more cost effective than generation alternatives. The lack of purchase power prices for the complete year 2000 at the writing of this EIS prevents an in-depth analysis.

Another development worth noting concerns the construction cost of combustion turbines. In the above analysis a $293 per KW value from AP-8 is used. Trade press reports indicate a year 2000 sellers' market for combustion turbines. This means that the $293 per KW value could be on the low side. It is worth noting that each 10 percent increase in the construction cost of combustion turbines would increase the relative total cost of a combustion turbine option an additional $3.4 million.[98] Should this development persist, it would favor construction of transmission line alternatives over combustion turbines.

Sensitivity of results to cost overruns for the Arrowhead-Weston project

Table 4-2 indicates that the yearly capital cost of the Arrowhead-Weston project is $19.3 million, based on a total construction cost of $222 million. It is worth noting that each 10 percent increase in the construction cost of the transmission line would increase the relative total cost of the Arrowhead-Weston line by an additional $1.9 million.

Environmental effects of combined-cycle and combustion turbine generation alternatives

The environmental impacts associated with construction and operation of combined-cycle or simple-cycle combustion turbines to meet all or a portion of the 1,560 MW of capacity are discussed in the last section of this chapter.

Cost calculations for 1,560 MW of reliability enhancement using renewable generation sources

The prior section compared the annual ratepayer or customer cost impact of combustion turbine and combined-cycle generation versus construction of the Arrowhead-Weston Transmission Project. This section makes the same comparison using two promising renewable energy resources for electricity generation: wind and whole-tree biomass. Because of the relatively high capital costs for wind and whole-tree biomass generation, the analysis in this section focuses on intermediate dispatch duty.[99]

As indicated above in the combined-cycle analysis, displacing 1,470 MW of import transfer capability associated with the Arrowhead-Weston Transmission Project would require 1,560 MW of new electrical generation by 2007. However, in the accompanying analysis wind generation is assumed to have a capacity contribution factor of only 50 percent, implying the need for twice the amount of new electrical generation or 2,940 MW of capacity.[100] In AP-8 the least expensive wind generation project had an ordinary construction cost of $1,112 per kW in 1999 dollars. Total cost for the construction of 2,940 MW of wind generation would be $3.27 billion. With respect to whole-tree generation, that type of project is assumed to have the same degree of availability as a conventional fossil fuel plant so that 1,560 MW would be needed. In AP-8 the least expensive whole-tree biomass electricity generation project had an ordinary construction

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[98] Calculated as 10 percent of the $34 million yearly capital cost for 1,560 MW of combustion turbines in Table 4-2.

[99] The relatively high capital costs make it unlikely that either wind or whole-tree biomass generation would be used for peaking purposes.

[100] The 50 percent value is an assumption intended to favor wind generation, as values between 7 and 30 percent have been debated in prior Advance Plans.

cost of $1,313 per kW in 1999 dollars. Total cost for the construction of 1,560 MW of whole-tree biomass generation would be $2.05 billion.

In order to compare renewable generation and transmission alternatives for cost effectiveness, the annual impact on rates must be analyzed. Table 4-7 presents the annual ratepayer and customer impact in 1999 dollars of using either 2,940 MW of wind generation or 1,470 MW of transmission line energy imports to meet Wisconsin's reliability-associated electricity needs. Table 4-7 also presents the annual ratepayer or customer impact in 1999 dollars of using either 1,560 MW of whole-tree biomass generation or 1,470 MW of transmission line energy imports to meet Wisconsin's reliability-associated electricity needs. Similar to the treatment for the conventional generation alternatives, certain assumptions are needed. First, all background assumptions used in the combustion turbine and combined-cycle analysis are also used here, except for the following:

- The levelized annual capital charge for wind generation is $90.30 per kW, and the levelized annual capital charge for whole-tree generation is $107.59 per kW.
- The marginal operating or energy cost of wind generation equals its AP-8 variable O&M value of $9.76 per MWh in 1999 dollars. The marginal energy cost of whole-tree generation, is $30.64 per MWh based on AP-8's characterization of a full load heat rate of 10,654 BTU per kWh, $2.72 per MBTU for biomass fuel, and $1.70 MWh for variable O&M.[101]
- Fixed O&M for the whole-tree generation project is the AP-8 annual estimate of $46.15 per kW in 1999 dollars.
- Wind generating projects receive a $15.00 per MWh tax credit under federal tax law.

The analysis in Table 4-7 shows that the annual operation of wind generation costs $239 million. Importing power using the transmission grid would cost between $170 and $176 million. This represents a cost savings of about 30 percent in favor of the line over the construction of the wind generation units. Consequently, the use of wind generation to displace the Arrowhead-Weston Transmission Project and associated power purchases at current market prices is likely not a cost-effective alternative.

The analysis in Table 4-7 also shows that the annual operation of whole-tree biomass generation is $393 million. Importing power using the transmission grid would cost between $170 and $176 million. This represents a cost savings of about 55 percent in favor of the line over the construction of the biomass generation units. Consequently, the use of whole-tree biomass generation to displace the Arrowhead-Weston Transmission Project and associated power purchases at current market prices is likely not a cost-effective alternative.

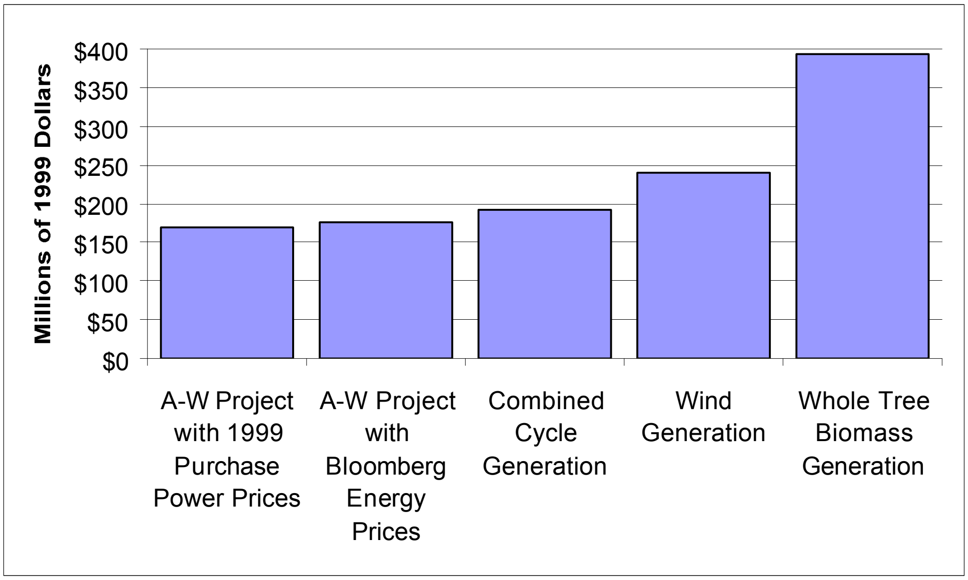
[101] The actual calculation is [(10,654*2.72)/1000] +[$1.70] = $30.63 MWh in 1999 dollars.

Table 4-7 Comparison of wind and whole-tree biomass generation versus transmission project costs using current purchase power prices

LOLE Reliability Perspective--Intermediate Duty 1999 Dollars	**Item**	**AP-8 Whole Tree Biomass**	**AP-8 Wind Generation**	**Method 1 A-W Project Avg. Purchase Power Prices**	**Method 2 A-W Project Bloomberg Power Prices**
Capital cost $/kW		$1,313	$1,112		
Capacity equivalence MW		1,560	2,940	1,470	1,470
Total construction cost (millions)		$2,048.3	$3,269.3	$222.4	$222.4
Levelized annual charge $/kW		$107.59	$90.30	NM	NM
Yearly capital cost (millions)	A	$167.8	$265.5	$19.3	$19.3
Capacity charge (millions)	B	$0.0	$0.0	$32.0	$32.0
Fixed O&M (millions)	C	$71.9	$0.0	$0.4	$0.4
Summer energy price $/MWh		$30.63	$9.76	$24.11	$32.50
Hours of summer duty		1000	1000	1000	1000
Summer energy cost @ 1470 MW (millions)	D	$45.0	$14.3	$35.4	$47.8
Fall energy price $/MWh		$30.63	$9.76	$24.11	$21.50
Hours of fall duty		800	800	800	800
Fall energy cost @ 1470 MW (millions)	E	$36.0	$11.5	$28.4	$25.3
Winter energy price $/MWh		$30.63	$9.76	$24.11	$19.89
Hours of winter duty		800	800	800	800
Winter energy cost @ 1470 MW (millions)	F	$36.0	$11.5	$28.4	$23.4
Spring energy price $/MWh		$30.63	$9.76	$24.11	$25.59
Hours of spring duty		800	800	800	800
Spring energy cost @ 1470 MW (millions)	G	$36.0	$11.5	$28.4	$30.1
1999 annual capacity & energy cost (millions)	H	$392.8	$314.3	$172.2	$178.2
Energy credit for reducing losses on system (millions)	I			$2.4	$2.4
Total costs excluding federal tax credit (millions)	J	$392.8	$314.3	$169.8	$175.8
Federal tax credit for wind generation (millions)	K		$75.0		
Total costs (million)	L	$392.8	$239.3	$169.8	$175.8
H=A+B…G					
J=H-I					
L=J-K					

It should be noted that the analysis in this section is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs. In addition, the analysis in this section assumes no Arrowhead-Weston project cost overruns and that 1,470 MW of capacity and energy would be available for purchase over the transmission grid.

Figure 4-3 Annual cost to electricity customers for 1,470 MW of intermediate-duty service using current purchase power costs



Cost comparison between installing new combustion turbine and the Arrowhead-Weston Transmission Project using the applicants' pure capacity reliability perspective

The original Arrowhead-Weston CPCN application indicates that the construction of the transmission line could save between $35 and $160 million over the years 2003 to 2032 period.[102] This range was subsequently updated by the applicants in an April 24, 2000 addendum. The new range indicates a potential saving to ratepayers of between $147 and $175 million. These estimates are in present value revenue requirement (PVRR) terms. Present value techniques place a current value on a future stream of costs or benefits measured in dollars, using a particular time value of money or interest rate. In the applicant's Table 8 analysis, 834 MW of combustion turbine capacity was used. This 834 MW cost analysis is based on the limited pure capacity view that the Arrowhead-Weston project would be used only for purposes of

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[102] See pages 47 to 48, Tables 7 and 8 in the November 10, 1999 "Arrowhead to Weston Transmission Line Project" Application, Volume 1, Docket 05-CE-113.

maintaining and enhancing reliability.[103] The following discussion examines the robustness of the applicants' present value claim.

With respect to combustion turbine units, in AP-8 the least expensive peaking-duty generation project as indicated earlier had an ordinary construction cost of $293 per kW in 1999 dollars when multiple units are constructed. The total cost for building 834 MW of peaking capacity would be $244 million and have an $18.18 million real levelized annual capital cost. With respect to the Arrowhead-Weston Transmission Project, the high-end construction cost estimate with all necessary improvements is $222 million, as indicated earlier. Based on a $222 million total cost, the real levelized annual capital cost would be $19.33 million per year in 1999 dollars. Similar to the treatment for the conventional generation units examined above, certain assumptions are needed:

- The levelized annual capital charge for combustion turbines is $21.80 per kW.
- As for the marginal energy cost of combustion turbines, the $32.80 per MWh estimate is based on AP-8's characterization of a full load heat rate of 11,133 BTU/kWh, $2.86 MBTU for natural gas fuel, and $0.96 per MWh for variable O&M.[104]
- Fixed O&M for combustion units is the AP-8 annual estimate of $2.50 per kW in 1999 dollars.
- Fixed O&M for the Arrowhead-Weston Transmission Project would be, as indicated earlier, $350,000.
- The energy and capacity price at times of super peak is $120.00 per MWh.[105]
- The analysis uses a comparative net energy credit for reducing losses on the overall transmission system due to the presence of the Arrowhead-Weston Transmission Project relative to using conventional generation. For super peak duty, the comparative net energy credit is $3.7 million and is comprised of 1 MW of saving at $30 per MWh for 24 hours when the combustion turbine generation would be running and 21 MW of saving at $20 per MWh for the remaining 8,736 hours.
- The transmission line analysis assumes 790 MW of transfer capability, which is equivalent to 834 MW of combustion turbine generation. (See the discussion of "equivalence" for conventional generating units, described above.)

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103 Earlier EIS cost analyses took the view that 1,560 MW was the appropriate value for maintaining and enhancing reliability. Under that LOLE reliability perspective 1,470 MW of additional power purchase over the Arrowhead-Weston line are compared to 1,560 MW of conventional generation in order to dynamically maintain the LOLE outage criterion of 0.1 day per year. Both the LOLE and pure capacity reliability perspectives are valid as indicated earlier.

104 The actual calculation is [(11,133*2.86)/1000] +[$0.96] = $32.80 MWh in 1999 dollars.

105 This value is assumed, but it compares to a 1999 Bloomberg energy price of $92.25 MWh for the highest non-price-spike day.

The analysis in Table 4-8 shows that the annual operation of 834 MW of combustion turbines for super peak duty would cost $20.90 million. Importing power using the transmission grid and the Arrowhead-Weston project would cost $18.29 million. This translates into an annual savings of about $2.61 million in 1999 dollars for the transmission line as compared to generation. The PVRR of these savings, over a 30-year time period, equals $38 million.[106] This $38 million savings estimate is below the updated range of the $147 to $175 million PVRR estimates provided by the applicants. Nonetheless, it is a positive present value in favor of the transmission project; consequently, the use of 834 MW of combustion turbines for pure reliability purposes is not likely a cost-effective alternative. This analysis is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs. In addition, estimates do not include the option value or credit of having a new transmission line available during off-peak periods to purchase potentially lower cost energy than that available without such a line. Lastly, it should be noted that present value results under this pure capacity approach are heavily influenced by the construction costs of both the combustion turbine and transmission line alternatives.

[106] Calculated as follows: 30 yearly payments of $2.61 million in 1999 dollars discounted by a real rate of discount of 5.5 percent, the value used in AP-8 to determine optimal long-range generation construction plans in Wisconsin.

Table 4-8 Comparison of combustion turbine generation and transmission project costs for 834 MW of pure capacity reliability

Applicant's Pure Capacity Reliability Perspective 1999 Dollars	Item	AP-8 CT Generation	A-W Project On-Peak Power Prices
Capital cost $/kW		$293	
Capacity equivalence MW		834	790
Total construction cost (millions)		$244.4	$222.4
Levelized annual charge $/kW		$21.80	NM
Yearly capital cost (millions)	A	$18.18	$19.33
Fixed O&M (millions)	B	$2.10	$0.35
Super peak energy and capacity price $/MWh		$32.80	$120.00
Hours of duty		24	24
Super peak energy cost @ 790 MW (millions)	C	$0.62	$2.28
1999 annual capacity & energy cost (millions)	D	$20.90	$21.96
Energy credit for reducing losses on system (millions)	E		$3.67
Total costs (millions)	F	$20.90	$18.29
D=A+B+C			
F=D-E			

Cost comparison between distributed generation resources and combustion turbines using applicants' pure capacity reliability perspective

As discussed in the prior section, the application's Table 8 reliability analysis uses 834 MW of combustion turbine capacity. This 834 MW cost analysis assumes a situation where the Arrowhead-Weston project would be used only for purposes of maintaining and enhancing reliability. The following sensitivity analysis replaces the use of combustion turbines with that of two alternative distributed generation resources: fuel cells and micro turbines.

A fuel cell generates electricity by combining hydrogen from a hydrogen-rich fuel (methane, methanol, propane, or biomass) with oxygen from the air to produce electricity, heat, and water. When fueled with pure hydrogen, the preferred feedstock, the only products are heat and water. All fuel cells consist of an anode, cathode and electrolyte, much like a battery, except that the reactant fuel is continuously fed to the cell. Electrochemical oxidation and reduction reactions take place at the electrodes to produce electrical current. Each individual fuel cell produces less than one volt of potential, so multiple cells must be used to obtain the desired voltage.

Different types of fuel cells have different levels of efficiency. Typical fuel cell capacity ranges from 200 kW to 2 MW with electrical efficiencies ranging from 40 to 57 percent; heat recovery can be as high as 85 percent. Utilizing the waste heat for some other purpose, such as cogeneration, can double the efficiency of fuel cells. Because fuel cells also have varying operating temperatures (ranging from 120 to 1,800 degrees F), not all fuel cells would be appropriate for all applications. The environmental effects of fuel cells are described later in this chapter.

The phosphoric acid fuel cell (PAFC) is the only type commercially available today, but both the U.S. Government and a number of private companies are doing intensive research and development work. Three additional fuel cell technologies are expected to be commercial in the next two to three years. They are molten carbonate (MCFC), solid oxide (SOFC), and proton exchange membrane (PEM).

Micro turbines are small gas turbines. They are self-contained sources of electricity (generally less than 300 kW) and heat that provide a controlled source of on-site power. They can be paralleled with other units or operated alone. Efficiencies vary from 24 percent to 55 percent, depending on initial cost and the utilization of waste heat. Natural gas is the primary fuel to be utilized although some renewable applications for bio-gas are being pursued.

Micro turbine technology dates back to the 1950 to 1970 time period, when the automotive market first considered gas turbine products. Stationary market interest was spurred by PURPA in the mid-1980s and accelerated during the 1990s. Micro turbines are a developing technology that hold the promise of higher efficiencies and lower operating cost, but this is a promise rather than reality at present. Barriers to widespread development include: (1) high initial cost; (2) reliable fuel supply; (3) the degree of customer attraction to a "high tech" product; and (4) in-service times to determine if the equipment can exhibit high reliability and long mean time between maintenance. Electric utility issues to be addressed include interconnection standards to protect distribution system integrity and safety and distribution tariffs that are fair to all customers but do not hinder development of distributed generation.

With respect to combustion turbine unit costs, in AP-8 the cheapest peaking-duty generation project had an ordinary construction cost of $293 per kW in 1999 dollars when multiple units are constructed. The levelized annual capital charge for combustion turbines is $21.80 per kW. This value is determined by using a conventional revenue requirements analysis. As for the marginal energy cost of combustion turbines, the $32.80 per MWh estimate is based on AP-8's characterization of a full load heat rate of 11,133 BTU/kWh, $2.86 MBTU for natural gas fuel, and $0.96 per MWh for variable O&M.[107] Fixed O&M for the combustion units is the AP-8 annual estimate of $2.50 per kW in 1999 dollars.

Commission staff has developed the following cost estimates with respect to micro turbines: the ordinary construction cost is about $900 per kW in 1999 dollars when multiple units are

[107] The actual calculation is [(11,133*2.86)/1000] +[$0.96] = $32.80 MWh in 1999 dollars.

constructed. The levelized annual capital charge for the micro turbines is $77.47 per kW, based on a conventional revenue requirements analysis using the same expected life span as that of a conventional combustion turbine. As for the marginal energy cost of micro turbines, the $21.95 per MWh estimate is based on an expected full load heat rate of 7,500 BTU/kWh, $2.86 per MBTU for natural gas fuel, and $0.50 per MWh for variable O&M.[108] Fixed O&M for the micro turbine units is also estimated at $5.00 per kW in 1999 dollars.

For fuel cells, the U.S. Department of Energy's (DOE) Energy Information Agency (EIA) has developed cost estimates.[109] The ordinary construction cost is about $2,163 per kW in 1999 dollars when multiple units are constructed. The levelized annual capital charge for the fuel cells is $185.94 per kW, which has been determined by a conventional revenue requirements analysis using the same expected life span as that of a conventional combustion turbine. As for the marginal energy cost of fuel cells, the $19.21 per MWh estimate is based on an expected full load heat rate of 6,000 BTU per kWh, $2.86 per MBTU for natural gas fuel, and $2.05 per MWh for variable O&M.[110] Fixed O&M for the fuel cells is also estimated at $14.74 per kW in 1999 dollars.

In the Table 4-9 analysis, which compares a conventional combustion turbine to micro turbines and fuel cells, certain other assumptions have been made. First, all three technologies are expected to operate either 24 hours of super peak duty, 850 hours regular peak duty per year, or 3,400 hours of intermediate duty.[111] Due to reserve margin requirements explained earlier, only 790 MW of the three technologies' capacity is used to actually generate electricity; the remaining 44 MW are held in standby.

The analysis in Table 4-9 shows that for 3,400 hours of intermediate duty, the annual operation of 834 MW of combustion turbines costs $108 million; using micro turbines and fuel cells would cost between $128 and $219 million annually.[112] The analysis in Table 4-9 also shows that for 850 hours of regular peak duty, the annual operation of 834 MW of combustion turbines costs $42 million; using micro turbines and fuel cells would cost between $84 and $180 million

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108 The actual calculation is [(7,500*2.86)/1000] +[$0.50] = $21.95 MWh in 1999 dollars.

109 Annual Energy Outlook 2000, Table 37, Cost and Performance Characteristics of New Central Station Electricity Generating Technologies, US DOE EIA. Available at http://www.eia.doe.gov/oiaf/aeo/assumption/tbl37.html

110 The actual calculation is [(6,000*2.86)/1000] +[$2.05] = $19.21 MWh in 1999 dollars.

111 This section looks at all three scenarios in order to render a comparison in the following footnote with the cost results from the LOLE reliability perspective earlier. A strict implementation of the applicants' Table 8 analysis would only require an examination of the 24-hour super peak situation.

112 It is important to note that in the earlier LOLE perspective analysis, combined-cycle units were found to be a more cost effective generating option than peaking combustion turbines for intermediate duty operation. Consequently, given the results here, the use of micro turbines or fuel cells by extension is not likely a cost effective approach relative to using combined-cycle units.

annually. The analysis in Table 4-9 further shows that for 24 hours of super peak duty, the annual operation of 834 MW of combustion turbines costs $21 million; using micro turbines and fuel cells would cost between $69 and $168 million annually. Both micro turbines and fuel cells have lower marginal costs of operation as compared to a conventional combustion turbine. However, their substantially higher fixed capital costs translate into an all-in cost that is much larger than that for the combustion turbines. Consequently, the use of 834 MW of micro turbines or fuel cells in place of combustion turbines for pure reliability purposes, as presented in the CPCN application's Table 8 analysis, is not likely a cost-effective alternative. Moreover, since the combustion turbine alternative is more expensive than the Arrowhead-Weston project and the import of power as indicated in the prior section, neither the more expensive micro turbines nor fuel cells would be cost effective versus the transmission project. This conclusion is based on what could occur in direct costs that affect electric rates; it does not factor in externality costs.

There is, however, an important caveat to the above conclusion. The analysis in Table 4-9 does not include the fact that distributed generation resources have the potential benefit of displacing some of those ancillary services required to run the electricity network. These ancillary services include generation resources used for regulation and frequency response, spinning reserves, operating reserves, voltage support, reactive power, as well as system control and dispatch. This means that distributed generation should receive a credit for avoiding the costs associated with the identified ancillary services. Unfortunately, it is not possible to quantify the value of this credit; in many ways the impact is still the subject of debate.

Table 4-9 Cost comparison of combustion turbine, micro turbine, and fuel cell technologies for 834 MW of electric system reliability

	AP-8 Multi-Unit CT	Micro Turbine	Fuel Cell
Fixed Costs			
Capital cost $/kW	$293	$900	$2,163
Levelized annual charge $/kW	$21.80	$77.47	$185.94
Fixed O&M $/kW	$2.50	$5.00	$14.74
Marginal Costs			
Variable O&M $/MWh	$0.96	$0.50	$2.05
Full load heat rate	11,133	7,500	6,000
Fuel cost	$2.86	$2.86	$2.86
Energy cost $/MWh	$32.80	$21.95	$19.21
Total All-In Costs $ Millions			
3,400 hours of intermediate duty	$108.4	$127.7	$219.0
850 hours of peak generation	$42.3	$83.5	$180.3
24 hours of super peak generation	$20.9	$69.1	$167.6
Values in 1999 dollars			

Assessment of future electric supply from the MAIN and MAPP regions

In prior sections, the relative cost-effectiveness of constructing a major new transmission line and importing electric power from the west and north into Wisconsin versus in-state electric generation was established. Such conclusions were based on different energy price forecasts. A major assumption behind such energy price forecasts is that the appropriate amount of electric supply would exist and be forthcoming. Depending on the cost analyses above, the appropriate amount of imported electric supply varied between 790 and 1,470 MW. This section examines whether there will be an adequate future electric supply to tap with a major new transmission line. The particular focus is on future power supply in the MAIN and MAPP reliability regions. The primary conclusion is that in non-summer months, there would likely be sufficient electric power supply quantities to tap in both MAIN and MAPP. During summer peak demand months, this would not likely be the case for the MAPP region. Expected power supply developments in the MAIN region have the potential for creating sufficient electric power supply.

MAPP U.S. region analysis

A recent report by MAPP indicates that in winter peak conditions there is likely a surplus of significant electric power capacity for the period 2000 to 2009.[113] The same study, however, casts doubt on whether ample supplies of electric power will be available from the MAPP U.S. region during summer months, especially during the period 2006 to 2009. Table 4-10 reports seasonal surplus and deficit power capacity values from the MAPP load and capability study for the U.S. part of MAPP. Surplus and deficit power capacity values are calculated with respect to maintaining a 15 percent reserve requirement. If proposed and committed electric power capacity exceeds the amount necessary to maintain a 15 percent reserve margin, then the excess is deemed surplus capacity with the potential for export. The converse situation applies and describes a deficit power capacity value.

Table 4-10 Committed and proposed MAPP U.S. region power capacity in excess of 15 percent reserves

	Summer	Winter
	MW	MW
2000	1,018	3,659
2001	261	3,571
2002	-182	3,581
2003	126	4,129
2004	111	4,023
2005	-564	3,341
2006	-1,741	2,343
2007	-2,324	1,792
2008	-2,988	1,361
2009	-3,218	1,492

Table 4-10 indicates that during the winter months, significant surpluses exist through the year 2009.[114] Such surpluses would suggest an increased ability of the MAPP U.S. region to export power to Wisconsin over a major transmission line connecting WUMS to the north and west. Table 4-10 also highlights that there is a slight MAPP power capacity surplus during summer months for the period 2001 to 2004. However, as internal MAPP electricity demand increases, the summer power capacity surplus turns into a significant deficit situation by the year 2009.

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113 "Mid-Continent Area Power Pool - U.S. Load and Capability Report", Mid-Continent Area Power Pool, St. Paul, MN, May 1, 2000.

114 While Table 4-10 reports winter results, it should be pointed out that the MAPP study found similar winter surplus results for non-summer months as well during the monthly period May 2000 to April 2002. In addition, it should be noted that scheduled maintenance of generating facilities may substantially reduce the "apparent" surpluses.

Such a summer period deficit would limit the ability of the MAPP U.S. region to export power to Wisconsin over a major transmission line connecting WUMS to the north and west.

While the supply assessment above indicates a good potential to import power from MAPP U.S. region during non-summer months, the ability to actually do so operationally warrants further analysis. Table 4-11 displays historical capacity factors for the major coal-fired power plants in Wisconsin and MAPP. In Wisconsin, the average capacity factor for coal-fired generating units was 67 percent during 1998 and 1999, with more efficient generating units achieving levels between 75 and 82 percent. In MAPP, the average capacity factor was also 67 percent. At such capacity factor levels, there would operationally be a limited, at best modest, ability to generate additional electricity for export to Wisconsin over a major transmission line connecting WUMS to the north and west.

Table 4-11 Coal-fired generating units 1998-1999 average capacity factors

State	Company	Facility	Capacity (MW)	Average Capacity Factor 98-99	Avg. Heat Rate BTU/kWh
MAPP Region & Wyoming:					
Minnesota	Northern States Power Co.	Sherburne Co.	2,300	64%	10,351
Montana	Montana Power Co.	Colstrip	1,552	79%	
Wyoming	Pacificorp	Jim Bridger	1,518	80%	10,645
Iowa	MidAmerican Energy	Neal	1,440	71%	10,275
Minnesota	Minnesota Power & Light	Clay Boswell	961	67%	10,641
Wyoming	Pacificorp	Dave Johnston	816	78%	11,298
Iowa	IES Utilities	Ottumwa	806	72%	10,559
Iowa	MidAmerican Energy	Louisa	738	64%	10,503
Iowa	MidAmerican Energy	Council Bluffs	725	66%	10,066
Wyoming	Pacificorp	Naughton	707	80%	10,632
Montana	Montana Power Co.	Colstrip	666	74%	
Minnesota	Northern States Power Co.	King	598	63%	10,093
Minnesota	Northern States Power Co.	Black Dog	505	32%	10,823
South Dakota	Otter Tail Power Co.	Big Stone	456	79%	9,982
North Dakota	Montana Dakota Utilities	Coyote	450	72%	11,603
Minnesota	Northern States Power Co.	Riverside	404	67%	10,616
Wyoming	Pacificorp	Wyodak	362	81%	11,807
Iowa	Interstate Power Co	Lansing	275	60%	11,769
Iowa	Interstate Power Co	ML Kapp	237	53%	11,397
Iowa	IES Utilities	Burlington	212	58%	10,697
Montana	Montana Power Co.	Corette	191	61%	9,330
Iowa	IES Utilities	Prairie Creek	148	58%	9,560
Minnesota	Northern States Power Co.	High Bridge	113	56%	10,642
			Average	**67%**	

State	Company	Facility	Capacity (MW)	Average Capacity Factor 98-99	Avg. Heat Rate BTU/kWh
Wisconsin:					
	Wis. Electric Power Co.	Pleasant Prairie	617	75%	10,530
	Wis. Electric Power Co.	Pleasant Prairie	617	77%	10,515
	Wis. Electric Power Co.	South Oak Creek	275	49%	9,580
	Wis. Electric Power Co.	South Oak Creek	275	58%	9,874
	Wis. Electric Power Co.	South Oak Creek	318	63%	9,309
	Wis. Electric Power Co.	South Oak Creek	324	60%	10,053
	Wis. Electric Power Co.	Valley	136	44%	15,981
	Wis. Electric Power Co.	Valley	136	46%	15,376
	Wis. Public Service Corp.	Pulliam	125	84%	10,250
	Wis. Public Service Corp.	Weston	322	82%	10,168
	Alliant Energy-WP&L	Columbia	512	76%	9,965
	Alliant Energy-WP&L	Columbia	511	80%	10,206
	Alliant Energy-WP&L	Edgewater	330	68%	9,578
	Alliant Energy-WP&L	Edgewater	380	79%	10,218
			Average	**67%**	

Source: FERC

MAPP Canadian region analysis

The above analysis centered on MAPP's U.S. operations; the following discussion provides a summer and winter electric supply assessment for MAPP's Canadian region. According to the North American Electric Reliability Council (NERC), MAPP's Canadian region in summer 1999 had 7,992 MW of net capacity resources along with 5,217 MW net internal electric demand.[115] This translates into 1,992 MW of excess summer electric power capacity when a 15 percent planning reserve margin is used. This calculation is portrayed in Table 4-12. For the year 2008, data in the NERC report indicate that the corresponding projected excess summer electric power capacity using a 15 percent planning reserve target would be 1,599 MW. This 1,599 to 1,992 MW range of projected surplus summer electric power capacity in MAPP's Canadian region could be available for export to either MAPP's U.S. region or to Wisconsin over a major transmission line connecting WUMS to the north and west.[116] With respect to winter supply availability in MAPP, however, little would be available for export according to Table 4-12.

[115] "Reliability Assessment 1999-2008, The Reliability of Bulk Electric Systems in North America," North American Electric Reliability Council, NERC, May 2000.

[116] Due to the large amount of hydroelectric power in Manitoba, this result assumes normal weather patterns prevail and not a permanent drought.

Table 4-12 MAPP Canadian region power supply assessment 1999-2008

	Summer 1999	Summer 2008		Winter 1999	Winter 2008
Net capacity resources MW	7,992	8,152		7,906	8,069
Net internal demand MW	5,217	5,698		6,387	7,006
15 percent reserve requirement	783	855		958	1,051
Capacity surplus/deficit MW	1,992	1,599		561	12

MAIN region analysis

Using data from the same NERC study, in summer 1999 MAIN had 567 MW of excess summer electric power capacity when a 15 percent planning reserve margin is used. This calculation is portrayed in Table 4-13. For the year 2008, data in the NERC report indicate that the corresponding projected excess summer electric power capacity using a 15 percent planning reserve target would be 5,509 MW. This value includes expected power supply additions from merchant power plants. The 567 to 5,509 MW range of projected surplus summer electric power capacity in MAIN could potentially be used in Wisconsin as long as transmission constraints did not prevent the ability to import power into Wisconsin. With respect to winter supply availability, significant amounts of excess supply are available in MAIN.

Table 4-13 MAIN region power supply assessment 1999-2008

	Summer 1999	Summer 2008		Winter 1999	Winter 2008
Net capacity resources MW	52,972	65,452		52,558	64,797
Net internal demand MW	45,570	52,124		36,205	41,591
15 percent reserve requirement	6,836	7,819		5,431	6,239
Capacity surplus/deficit MW	567	5,509		10,922	16,967

Future power supply assessment caveats

The analysis above focuses particularly on electric supply capacity and the ability to provide firm electric power during peak electric demand conditions. The analysis examines only the potential of such supply to exist. Such potential in practice is affected by the existence of transmission constraints. The analysis above took an optimistic view of such constraints. The analysis above also excludes the economic pricing of such electric power supply, including appropriate wheeling tariffs. Lastly, the forecasts of power supply for both MAIN and MAPP are affected by the relative inability to correctly forecast merchant power plant developments.

Analysis of Integrated Alternative

Background

Comments on the draft EIS included suggestions that the Commission complete an integrated analysis that compares the proposed line to an integrated set of other transmission and non-transmission (conventional generation, distributed generation, energy efficiency, pricing strategies) options. Commission staff knows of no models or described methods for conducting this type of integrated analysis. The Advance Plan process, which was the most comprehensive electric system planning process used in Wisconsin, did not integrate transmission needs with generation, energy efficiency, or pricing. The Advance Plan did employ integrated analysis methods to compare non-transmission options to each other, but did not compare them to transmission options.

The best approach available is to determine the need for system improvements and the cost required to meet the need with the proposed project, and then compare that with the cost of other options. The goal would be to find an integrated solution that meets the need at a cost lower than the proposed option and is technically feasible to implement.

In building such a package, the Commission must consider the statutory energy priorities described earlier in this chapter, in the energy efficiency section.

When evaluating how much energy conservation to include in an integrated mix of alternatives, the Commission must also consider that it no longer has the same authority to ensure the implementation of energy efficiency. For the foreseeable future, the majority of efficiency activities will be undertaken by DOA.

The first step in evaluating the degree to which a combination of generation, transmission and energy efficiency improvements could meet the need that the proposed line is intended to address must focus on transmission. Specifically, this first step should assess the potential for using smaller incremental improvements to the existing transmission system, to increase its ability to import power. Then, the amount of additional generation, energy efficiency, pricing changes and other measures that are required to complete an integrated alternative can be assessed. Once each of these values has been determined, an estimate of total cost and the environmental impact of an integrated alternative could be developed and compared to other alternatives.

Preceding sections of this EIS suggest that if enough new generation is built within Wisconsin, the need for a major new transmission line could be significantly reduced. In this light, the alternative transmission lines considered in the WIRE study and compared in Table 3-6 may not represent the full range of transmission projects that could meet the need for system improvement as part of an integrated alternative. PSCW staff conducted an analysis to determine the potential of transmission reinforcement projects that do not include major new lines on the scale of the proposed project or the alternatives considered in the WIRE study and discussed in Chapter 3.

Import capability improvements achievable without a major new EHV line

This section focuses on examining a set of transmission improvements significantly more modest than either the proposed project or the alternative transmission lines discussed in Chapter 3, that nonetheless would improve the ability of the transmission system to move power into Wisconsin, relative to what is possible today. The most appropriate place to begin developing such a set of improvements is to add all relevant transmission improvements that utilities now plan to build, for reasons other than improving eastern Wisconsin's import capability, in the next few years. This is the same approach taken by the utility transmission planners who conducted the WIRE study, but their model should be updated to reflect the most recent set of plans for transmission improvements in Wisconsin. The Wisconsin utilities' filings for the 2000 SEA include all significant transmission projects they expect to begin construction by 2002.[117] Examination of this list shows that some projects now planned to be built in the next few years could facilitate imports into eastern Wisconsin.

In Monroe County, WP&L plans to rebuild the existing 69 kV Monroe County-Council Creek transmission line (which extends, roughly, between Sparta and Tomah) as a 69/161 kV double circuit line. In Vernon and Sauk Counties, WP&L plans to build a new 161 kV line between the Hillsboro Substation of DPC and WP&L's Reedsburg Substation. In addition, it would build a 138 kV line from Reedsburg to the Kilbourn Substation in Wisconsin Dells. These projects would alleviate imminent problems in the project areas, benefits that were assessed and described in AP-8.[118] In addition, they would contribute to improving transfer capability.

While WP&L's SEA filing indicates that it plans to build these lines, WP&L also plans to divest its transmission facilities to the ATCo by January 1, 2001. Thereafter, it will be the responsibility of the transmission company to plan, apply for and build transmission projects in this area. In this light, it may seem that there is little assurance that WP&L's plans will in fact proceed. However, representatives of the transmission company have stated that, in general, they would expect to follow through on projects that are part of the near-term plans of utilities that are joining the transmission company, and that they would expect to adhere to a similar schedule.

One other transmission line upgrade has potential to significantly improve system transfer capability. The transmission line that stretches due east from Chippewa Falls to Wausau is built to 161 kV specifications but operated at 115 kV. This line could be converted to 161 kV operation if transformers and other substation equipment were modified along the line. This increase in voltage would increase the amount of power flowing on this line, decreasing the loading on other, perhaps more sensitive facilities.

At the time Commission staff performed this analysis, NSP and DPC had negotiated a settlement with some parties to revise their proposal to build a 230 kV line between the Chisago

[117] The draft SEA report is available at http://www.psc.state.wi.us/cases/sea/index.htm.

[118] Advance Plan 8 Technical Support Document D23o, Southwest Wisconsin Study.

Substation in Minnesota and the Apple River Substation in Wisconsin. The new proposal involves construction of the line at a lower voltage. Not all parties support this proposal and it remains unclear whether and at what voltage this line will be built. Commission staff's modeling effort assumes that this line would be built at 115 kV.

When eastern Wisconsin is importing large amounts of power, the Wempletown-Paddock 345 kV line, extending from northwest of Rockford, Illinois to west of Beloit, becomes heavily loaded. Should this line trip out of service, it could lead to the overload of other critical lines, posing a limit to the ability of the system to transfer power. This existing line consists of a single transmission circuit installed on double circuit structures. If a second circuit were installed, such overloads would be prevented from occurring due to single circuit outages. Simultaneous outages of both circuits would still be a potential problem. Commission staff's analysis assumes that this second circuit would be installed.

If the proposed Arrowhead-Weston and Tripoli-Rhinelander lines are not built, WPSC will have to take other steps to ensure reliable service in the Upper West area. Staff's analysis assumes that WPSC would build system reinforcements as described in its AP-8 Upper West area transmission planning study.

In addition, the transmission modeling effort completed by Commission staff revealed the need for capacitor additions and a variety of other transmission upgrades, similar to those found necessary for several WIRE transmission alternatives. (See Table 3-8, for example.) The full list of changes to the WIRE study base case assumed in Commission staff's analysis, in addition to the items listed in Table 3-8, is presented in Table 4-14. This collection of transmission improvements constitutes Commission staff's Lower-Voltage Reinforcement transmission alternative. This alternative is meant to be considered as one part of a broader integrated solution. It is not considered to be a viable stand-alone alternative to the electric system needs discussed in Chapter 2.

Table 4-14 Transmission reinforcements in staff's Lower-Voltage Reinforcement alternative

Transmission Reinforcement Project	Present Status	Project Description	Approx. Length of Line
Monroe Co.-Council Creek 161 kV line	Included in WP&L's SEA filing for 2000	Rebuild existing single-circuit as a double-circuit 69/161 kV line	16 miles – on existing ROW
Hillsboro(DPC)-Reedsburg 161 kV line	Included in WP&L's SEA filing for 2000	New 161 kV line	28 miles
Reedsburg-Kilbourn 138 kV line	Included in WP&L's SEA filing for 2000	Rebuild existing 69 kV line as 138 kV or 69/138 kV line	14 miles – on existing ROW
Sunrise Tap-McCue 138 kV line	Included in WP&L's SEA filing for 2000	New 138 kV line	10 miles
Convert Hydrolane-Sherman St. 115 kV line to 161 kV operation	No current plans	Upgrade voltage of existing facilities	85 miles – convert existing line no new ROW
2nd Wempletown IL -Paddock WI 345 kV circuit	No current plans	Add new circuit to unused portion of existing double-circuit structures	2.5 miles in Wisconsin – no new ROW
Chisago MN -Apple River WI line at 115 kV	Approved by PSCW at 230 kV Settlement negotiated at 161 kV Approval at 161 kV pending	New line	26 miles in Wisconsin
2nd Skanawan-Highway 8 (Rhinelander) 115 kV circuit	Approved for planning purposes in Advance Plan 8	Replace an existing 115 kV line with double-circuit construction	16 miles – on existing ROW
2nd Black Brook-Aurora St. 115 kV circuit	Approved for planning purposes in Advance Plan 8	Replace an existing 115 kV line with double-circuit construction	8 miles – on existing ROW
46 kV line via Grandfather Falls fully upgraded to 115 kV specifications	Approved by PSCW, work by WPSC suspended pending Arrowhead-Weston decision	Rebuild existing facilities	16 miles – on existing ROW
Maine-Brokaw 46 kV line, built for 115 kV operation	Engineering plan filed 7/19/00, October 2000 application planned	New 115 kV line	2 miles
46 kV Weston-Brokaw line fully upgraded to 115 kV specifications	Approved for planning purposes in Advance Plan 8	Rebuild existing facilities	14 miles – on existing ROW
Capacitors as in WIRE study case 1c	No current plans	New substation equipment	No ROW required
Additional Capacitors	No current plans	New substation equipment	No ROW required

Transmission analysis inputs and methodology

In examining this set of transmission improvements, Commission staff employed an analysis methodology largely similar to that used in the WIRE study that underlies the project application. The analysis focused on ability of the system to support imports into eastern Wisconsin, from sources to the west as well as sources to the east and south. The base power system models used in the WIRE study, including the sources of power used to establish imports into Wisconsin, were used in Commission staff's analysis as well.

Import limits were determined first using an approximate, linear extrapolation technique. This method is often used because the calculations involved are much less demanding than is true for the full calculation. Because of the approximate nature of this technique, however, a non-approximate technique was then employed to test the results of the preliminary analysis. This more accurate technique was used to assess the performance of the system with 1,000 MW of imports into eastern Wisconsin from the south and, simultaneously, varying levels of imports from the west.

The WIRE study used a different model for the voltage stability analysis than it did for the primary power flow analysis, and Commission staff adopted this same approach and model, as well as aspects of the same detailed procedure to assess the voltage stability characteristics of the Lower-Voltage Reinforcement alternative. Results of all these analyses are described in the next section.

A detailed transient (dynamic) stability study was conducted as part of the WIRE study. In its analysis, Commission staff did not have the resources or expertise to replicate this study for its analysis of the Lower-Voltage Reinforcement alternative. However, the next section does discuss possible approaches to mitigating dynamic stability problems without a new EHV line.

Results

Thermal limits

When linear extrapolation techniques were used to assess the performance achievable with the Lower-Voltage Reinforcement alternative, it appeared to be capable of achieving transfer levels near the 3,000 MW criterion used in the WIRE study.

However, the use of this linear extrapolation approximation technique tends to overestimate the performance that can be achieved, by neglecting some effects that become increasingly severe obstacles to power transfer as the level of power flowing on the system increases. Commission staff's analysis uses a more accurate estimation technique for the case of 1,000 MW of imports from the south and a larger level of imports from the west, but like the WIRE study analysis, does not do so for the case of imports from the south in excess of 1,000 MW. Commission staff's work shows that some limits appeared considerably earlier in the detailed analysis than they did in the approximate analysis. Specifically, it appears that the Lower-Voltage Reinforcement alternative would allow about 1,400 MW of imports from the west, simultaneous with 1,000 MW of imports from the south.

The difference between the linear (approximate) analysis and the full, non-approximate analysis is probably more pronounced in the case of imports primarily from the west than is true for imports primarily from the south. This is because of the relatively large number of EHV lines between Wisconsin and Illinois, as compared to the single, long EHV line between eastern and western Wisconsin. For this reason, the results of the linear estimate for imports primarily from the south probably provide a good estimate of the value that would be obtained with more detailed analysis. Based on thermal limitations, then, it appears that the Lower-Voltage Reinforcement alternative could support approximately 1,000 MW of imports from either direction, simultaneous with about 1,400 MW of imports from the other direction.

Voltage and dynamic stability limits

These limits – 1,000 MW from one direction simultaneous with 1,400 MW from the other – are consistent with application of the WIRE study voltage stability analysis to the Lower-Voltage Reinforcement alternative, which showed only slightly more susceptibility to voltage problems than the proposed line.

Dynamic stability considerations may also pose limits on the amount of power that can be imported into Wisconsin. For this reason dynamic stability was included in the WIRE study. Commission staff, however, did not have the resources available to assess the dynamic stability limits that would be present without a major new EHV line. Such an analysis would have to be conducted in order to confirm the level of transfer that any transmission alternative could achieve. Any such analysis should consider the possibility of alleviating any problems that show up in the analysis by dealing with the initiating event.

In order to understand this point it is necessary to appreciate the nature of dynamic stability events that could pose a transfer limit. Transfers may be limited by system operators to prevent the possibility of a serious power system disturbance. Such a disturbance could be initiated by an event such as a short circuit or the action of protective circuit breakers in the transmission system. While there are a great many such events that could occur, typically a relatively small number of these events have the most severe consequences and pose the greatest concern. Accordingly, while a major new EHV line provides a robust way to alleviate dynamic stability concerns, it may also be effective to focus on preventing the particular disturbance-initiating events of concern.

There may be a number of ways to do this – installing faster circuit breakers, installing redundant circuit breakers, or changing substation configurations to minimize the disruption to power flow caused by circuit breaker operation. If the number of such initiating events that are significant for limiting power transfer is small, then it may be reasonable to overcome this limitation by directly attacking the initiating event, rather than reinforcing the larger system.

System operators in Wisconsin and Minnesota observe a particular limit at present, in part to alleviate dynamic stability concerns. It would be possible to achieve 1,400 MW of imports from the west into eastern Wisconsin with the Lower-Voltage Reinforcement alternative while remaining well within this "Minnesota Export" limit. Additional power flows from Minnesota to other states to the south and east, however, could eventually eliminate this margin, causing the limit to be reached.

Arpin phase angle problem

As discussed in Chapter 2, one of the most significant problems with the existing power system concerns the large phase angle difference that appears between the Eau Claire and Arpin substations when the connecting 345 kV line is forced out of service during periods of heavy west-to-east power transfers. This often poses a restriction on power transfer in today's system, even though the present-day operating limit is higher than that which would be required to allow immediate reclose of the line.

Commission staff analysis, however, indicates that, with the improvements identified in Table 4-14, the phase angle problem should not prevent immediate reclose at import levels up to 1,000 MW from the south and 1,400 MW from the west. Since imports from the west have the greatest impact on the Arpin phase angle, it can be assumed that immediate reclose of this line could also be accomplished at import levels of 1,400 MW from the south and 1,000 MW from the west.

Installation of new power plants in the area around Stevens Point could further reduce the impact of line reclose on other parts of the power system, provided they were operating at the time. Even higher flows could be accommodated by installing special equipment at the Arpin substation.[119]

Other operating guides

Up to an import level of 1,400 MW from the west and 1,000 MW from the south, the Lower-Voltage Reinforcement alternative appears to eliminate the need for the same western-interface operating guides as the proposed Arrowhead-Weston project does for higher transfer levels – up to import levels of 2,000 MW from the west and 1,000 MW from the south. When the Arpin-Rocky Run 345 kV line trips out of service, neither Arrowhead-Weston nor the Lower-Voltage Reinforcement alternative eliminates the need to open parallel transmission connections. Nonetheless, the Lower-Voltage Reinforcement alternative would allow a higher level of transfers before this operating guide is required than is true at present, and the Arrowhead-Weston line would allow a higher level yet.

[119] The simplest solution would be to install a 345 kV switched series reactor at the Arpin substation. This device would normally be disconnected from the transmission system, but upon a trip of the Eau Claire-Arpin line, it would be inserted in series with the transmission circuit before reclosing the line. A reactor acts to resist the flow of alternating-current electricity, and can reduce the magnitude of the power surge that accompanies line reclose. Once the line has been reclosed, the reactor could be bypassed and then removed from the circuit.

Other characteristics of the Lower-Voltage Reinforcement alternative

While the set of transmission improvements in the Lower-Voltage Reinforcement alternative would allow significantly higher transfer levels than are possible today, it would not have all the beneficial power system impacts that a major new EHV transmission connection across Wisconsin's MAPP-MAIN interface would. Specifically, the WIRE study found that, to varying degrees, the major new EHV lines considered in that study would reduce system losses and would relieve loading on other facilities in the region that tend to pose limits to regional transfer. The Lower-Voltage Reinforcement alternative would yield a much smaller improvement in these areas.

Environmental Effects of the Alternative System Improvements

The environmental impacts associated with construction and operation of possible system improvements to achieve 1,560 MW of generation capacity could be substantial, depending on the generation technology used and the site(s) selected for one or more plants. While coal-burning or nuclear facilities used to be the industry standard for generation plants greater than 700 MW, the feasibility of constructing intermediate-load or even base-load plants fueled by natural gas has increased in recent years. In addition, continued research and testing of distributed generation devices such as fuel cells and micro turbines is expected to increase commercial availability of these technologies rapidly over the next several years. Sites in Wisconsin and other states in the Midwest have been used to install increasing amounts of wind generation and other sources of renewable energy.

The various generation types analyzed for this EIS could be used to supply all or a portion of the needed capacity. A brief assessment of the major environmental effects of constructing and operating these sources is described below. A more detailed analysis would require specific information about the size, location, and type of plant proposed. An application for construction of a major generating plant (100 MW or greater) would require the issuance of a CPCN from the Commission. The full range of environmental and human impacts would likely be described in a detailed EIS. Opportunities for public involvement would be provided through a scoping process, solicitation of comments, and a public hearing

Impacts related to combined-cycle and simple-cycle combustion turbines (CT)

Adequate gas supplies and the development of a competitive market have led to an increased number of new gas transmission pipelines throughout the Midwest within the past several years. Because of this, natural gas-fired peaking plants (simple-cycle combustion turbines) and intermediate-load, natural gas-fired combined-cycle units appear to be the current technology of choice throughout the industry.

Simple-cycle combustion turbines are generally designed and installed in 150 MW or 225 MW increments. Also, smaller units (< 100 MW) are sometimes installed at existing plant sites to increase capacity. Because they are less efficient than combined-cycle units, they are run for significantly fewer hours per year. Simple-cycle plants and combined-cycle plants have many of the same types of environmental impacts. These impacts vary in extent due to the number of hours of operation and the resource needs of the two plant types.

The potential environmental and socioeconomic impacts of a typical combustion turbine would likely be comparable to those of the SEI Generating Facility approved by the Commission and constructed in the Neenah-Menasha area in Winnebago County in 1999. This is a 300 MW facility composed of two simple-cycle combustion turbines.

The potential environmental and human impacts associated with one or more 800 to 1,000 MW combined-cycle plants would likely be comparable to the environmental effects of the Badger Generating Facility currently under review by the Commission. The Badger Generating plant is a 1,050 MW combined-cycle facility composed of four individual units that can be operated simultaneously or independently. An application for construction authorization was filed in December 1999 and a Commission decision is scheduled for fall of 2000.

The major environmental and human impacts related to construction and operation of a 1,000 MW combined-cycle plant and 300 MW of simple-cycle combustion turbines are outlined below. The impacts associated with a 500-600 MW combined-cycle plant or a 150 MW CT would be somewhat less than those described but similar in scope.

Land area affected

A simple-cycle combustion turbine consists of a compressor, a combustion chamber, gas turbine, and exhaust stacks. A 20- to 30-acre site could accommodate this equipment and allow adequate space for a buffer around the plant to limit the effects of construction and plant noise. The components of a combined-cycle plant are similar except that a steam turbine is needed in addition to a gas turbine and cooling towers are also commonly used. About 30 to 50 acres of land would be required to adequately support these components. An additional area of buffer surrounding the plant would lessen the aesthetic impacts of the plant as well as aid in reducing noise during plant construction and operation. Including an adequate buffer area, a parcel about 70 to 100 acres in size could support a 1,000 MW combined-cycle plant.

Water use and discharge

Water use requirements for a 300 MW CT plant would be approximately 50 gallons per minute (gpm) during times of operation using the primary fuel of natural gas. Up to 550 gpm could be needed when such a plant is running on fuel oil (the typical back-up fuel). In most cases, a high capacity well could supply the needed water without adversely impacting private or municipal wells. Because the plant would require use of demineralized water for pollution control, raw water would be stored in a large tank and run through a demineralizer as needed. Discharge of wastewater during normal operation and maintenance would be minimal and could likely be released to the local sanitary sewer system.

The amount of water required to operate a 1,000 MW plant is significant. At the proposed Badger Generating facility approximately six million gallons per day would be used for evaporative cooling and steam cycle make-up, power augmentation, and other various purposes during plant start-up. Water for fire protection and sanitary needs is also included in this volume. Provision of water services by a municipal water utility, rather than a new source well, would lessen the potential for draw-down effects on nearby private wells, streams, and wetlands.

Water discharge would be expected to be in the range of 1.5 to 2.0 million gallons per day. If this discharge can be handled by a local sanitary sewer system, there would be no effects on nearby natural water bodies. However, discharging this amount of wastewater into a natural water body, especially if there is a temperature difference in the discharge water and the receiving water, could result in substantial adverse effects on water quality and aquatic life.

Fogging and icing

Fogging and icing are not associated with the operation of simple-cycle combustion turbine plants.

Waste heat from the power plant steam cycle condenser of combined-cycle plants is released into the outside air through cooling towers. This may produce a water vapor plume that can affect driving conditions by creating a fog or ice on nearby roads when temperatures are below freezing. The plume may also be considered to be an adverse visual impact by nearby landowners. Plume development can be mitigated to some extent by using specially designed cooling tower technology.

Air quality effects

Some portions of the state are classified as "non-attainment" areas if the ambient air quality standard for one or more criteria air pollutants is not met. Much of southern Wisconsin is classified as "non-attainment" for ozone. Federal regulations require major pollutant sources[120] to apply the Best Available Control Technology (BACT) to meet standards for particulates (PM), nitrogen oxides (NOx), carbon monoxide (CO), and sulfur dioxide (SO_2). Implementation of BACT could add a substantial cost to the plant. An estimate of potential emissions in lbs./hr. for a 360 MW simple-cycle combustion turbine and a 1,050 MW combined-cycle plant is shown in the Tables 4-15 and 4-16.

Table 4-15 Estimate of potential emissions for a 360 MW simple-cycle plant

Pollutant	NOx	SO_2	CO	PM_{10}	VOC
Lbs./hr.	210.0	7.88	120	43.2	7.2
Tons/yr.	68.1	2.56	39.0	14.0	2.3

[120] A plant that emits over 100 tons per year of at least one criteria pollutant is classified as a major source by the DNR.

Table 4-16 Estimate of potential emissions for a 1,050 MW combined-cycle plant

Pollutant	NOx	SO_2	CO	PM_{10}	VOC	Formaldehyde	Ammonia
Lbs./hr.	101.9	18.0	53.2	122.0	11.2	29.6	109.2
Tons/yr.	470.9	75.6	898.9	529.7	47.8	55.0	466.1

The values shown above assume the installation of a control technology for reducing NOx emissions, either dry low-NOx combustors or selective catalytic reduction. The projected emissions from any new combined-cycle plants would have to be considered in combination with other existing power plants in the combustion impact area to ensure compliance with the National Ambient Air Quality Standards (NAAQS).

Noise

Noise during site preparation and construction would be typical of any major construction project. During plant operation, periodic noise impacts from short-term steam or air blows could exceed local ambient noise levels. Enclosing the units within buildings lined with soundproof materials and using baffles to reduce the noise of air inlet coolers could mitigate these impacts to some extent. Depending on the proximity of residences and business to the new generating plant(s), audible noise issues might arise.

In addition, some power plants in Wisconsin have exhibited problems with low frequency sound and vibrations. In general, this is more likely to be a problem with operation of a simple-cycle combustion turbine unit than a combined-cycle facility. Technical solutions could include a specially designed noise attenuation system for each combustion turbine, although such systems are very costly. Purchasing properties and relocating residents that are very close to the plant is another option that has been used.

Aesthetics

Depending on the surrounding land use and future land-use plans, the impacts of a new generating plant on the visual and social character of the nearby communities may or may not be significant. Sites located in industrial settings or in close proximity to similar utility infrastructure may be more compatible with their surroundings and acceptable to the public than sites in residential, agricultural, or wooded settings. Creation of landscaped berms and use of other trees and shrubbery to mitigate the visual impacts of the plant could be implemented. The stacks are generally 120 to 130 feet high and are the most readily visible feature of the plants.

Transmission effects

An intermediate-duty plant approaching 1,000 MW in size would require a high-voltage interconnection to the transmission system and an adequate gas supply line. The electric and gas transmission system impacts related to such interconnections would have to be assessed through detailed studies. Electric transmission line construction is one of the most controversial aspects of any new electric project. Siting the plant close to existing lines (electric and gas) can largely reduce public concerns about property values, EMF, induced currents, and safety issues.

A lower voltage line could possibly be used to interconnect a small combustion turbine plant to the transmission grid, but lines over 100 kV are commonly used.

Environmental effects of renewable generation alternatives

As stated in the economic analysis, displacement of 1,470 MW of import transfer capability (as provided by a new major EHV transmission line) would require approximately 2,940 MW of wind generation or 1,560 MW of biomass generation. Due to limited wind resources and land availability (for growing biomass fuels) in Wisconsin, this is not a realistic scenario. However, use of these technologies as part of an integrated approach to meeting capacity needs may be feasible.

Wind power

The environmental advantages of wind generation are numerous. It does not produce air pollutants, require water for combustion or equipment cleaning, or discharge wastewater or solid wastes. Thus, impacts related to water supply, depletion of ground water, and flows to surface waters are avoided. In addition, transportation, treatment, and storage of solid wastes are avoided.

There are also socio-economic advantages associated with wind generation. Rather than purchasing property for siting the turbines, as is typically done in the case of coal or gas-fired plants, wind developers often prefer to use leasing agreements or annual payment systems that are based on the annual output of the turbines operating on the property. The steady income from these agreements can be an important benefit to landowners. Wind farms could also increase the number of local jobs because they tend to require more full-time personnel per unit of power produced than conventional gas-fired plants. Noise emanating from a typical wind turbine at a distance of about 800 feet would not be expected to exceed the typical sound levels found in a quiet suburban residential neighborhood.

With respect to adverse environmental effects, the potential for causing avian mortality is one of the major environmental problems associated with wind power. Bird collisions with turbine blades and towers have been well documented in this country and abroad. Areas supporting sensitive avian resources should be avoided when siting wind facilities.

Turbines, commonly used in the Midwest, are mounted on tall, tubular, steel towers. The swept area of the turbine blades is approximately 160 feet, resulting in a total height of about 290 feet. Because turbines are generally located at high elevations where wind speeds are the greatest, they are almost always visible from the surrounding countryside. Because of their size and unusual form, wind turbines can have a significant effect on local aesthetics, especially in areas where protection of important viewsheds or scenic resources is important.

In general, locations in eastern Wisconsin along ridges and escarpments in open country have been found to be the most suitable locations in the state for location of wind turbines. However, with the advent of larger and taller machines, other areas in Wisconsin may be attractive for wind energy development. Approximately 5 acres of open land can accommodate about 15 turbines, which can produce 10 MW of wind power.

While public surveys have indicated that there is a strong willingness on the part of electricity consumers to pay for power generated from renewable resources such as wind, public acceptance of siting wind turbines in rural communities has been primarily negative.

Biomass

Whole tree biomass is another renewable resource considered in this EIS as a partial replacement for the 1,470 MW of transfer capability provided by an EHV transmission line. Whole tree energy involves growing, harvesting, and burning plantation-grown trees, making the process a closed-loop system with respect to the carbon dioxide (CO_2) cycle. About 80,000 acres would be required to grow enough trees necessary to produce 100 MW of energy. This land would be dedicated solely to the growth of fuel. Studies indicate that the land would provide better habitat for birds and small animals than cropland, but less desirable habitat than existing woodlands. Some concerns have been expressed about the effect on local and regional biodiversity of cultivating a single tree species on a massive scale.

No exceptional water use would be required for the growth of fuel, although a well or major water supply would be needed to supply water to the combustion facility to produce steam to generate electricity. The burning of wood also results in emissions of SO_2 and NOx. Over time, the amount of CO_2 emitted during combustion would be recaptured in the woody vegetation during its growth cycle.

With respect to socioeconomic effects, growing and harvesting the trees required for a whole tree energy operation could produce many jobs within the state.

Environmental effects of fuel cells and micro turbines

Hydrogen, the required fuel source for fuel cells, can be produced from water using electrolysis, with the necessary electricity generated using renewable energy. NASA is currently working on a "regenerative fuel cell" that would be a closed-loop form of power generation. In the regenerative fuel cell water is separated into H_2 and O_2 by a solar-powered electrolyser and fed into the fuel cell to produce electricity and water. The water is then re-circulated to the electrolyser to complete the cycle. However, because this method is relatively expensive, most fuel cell systems use some form of hydrocarbon fuel as their hydrogen source. When a hydrocarbon fuel is used, there may be gas, liquid, or solid waste by-products from the process.

Some source compounds will have fewer and smaller amounts of by-products. Following is a list of hydrogen sources that rank from lowest to highest in by-products:

1. Water – none
2. Methane
3. Propane and natural gas
4. Gasoline
5. Fuel oil
6. Gasified coal

Fuel cells, because of higher efficiencies and lower fuel oxidation temperatures, emit less CO_2 and NOx per kWh of power generated than turbines or engines that rely on a combustion process. The overall air emissions are lower for fuel cells, but the difference is not significant for SO_2 or particulates. Table 4-17 compares the emissions from three distributed technologies that use natural gas as the fuel or the source of the fuel.

Table 4-17 Comparison of the air emissions and efficiency of distributed generation technologies using natural gas

Technology	NOx (#/MWh)	SO_2 (#/MWh)	CO_2 (#/MWh)	Particulates (#/MWh)	Efficiency Range
CT					
Standard wet NOx burners[1]	8.11	0.04	3909	0.53	24%
New dry low NOx burners[2]	0.61	0.02	1200	0.12	32%
Micro turbine (<500kW)					
Average[3]	0.75	0.02	1348	0.12	25-30%
Fuel cell system (200kW-2MW)					
Average [4]	<0.05	0	800	0.10	40-57%

1. Measured level of emissions, EPA e-grid 1997.
2. EIS for SEI Wisconsin LLC by PSCW staff.
3. Gas Research Institute and manufacturers data.
4. Fuel Cell Information Systems.

If fuel re-forming is done on site, heat produced from the fuel cell process powers the reformer. If the re-forming is done off site, the resultant pollutants would be produced off site, and there would be additional pollutants from transporting the hydrogen to the fuel cell site. Unlike gas-fired combustion turbine and combined-cycle units, noise and vibrations associated with fuel cells are practically non-existent because the fuel cell itself has no moving parts.

The cost of fuel cells is still too high to compete with other forms of distributed or central generation, except at remote locations. There are projections that the cost could decrease enough to be competitive for general use by 2004, but that the market could not develop enough to supply large numbers of small customers until 2010.

Greater use of fuel cells would benefit natural gas companies because it would increase their sales and level their load. Others who are interested in promoting this market are investors, some dual fuel utilities, electric utilities with particular types of need, electric customers who are far from the nearest distribution line, and some small remote electric applications such as traffic lights and remote livestock water pumps.

Although there will be a slow shift to newer cleaner generating technologies such as fuel cells, they are not likely to decrease current generation/transmission needs for several years. Distributed generation, however, may be good for planning to meet future needs, especially peak needs beyond 2008.

For more detailed information on fuel cells see Report number 193-2 from the Energy Center of Wisconsin (WWW.ECW.ORG), *Review of State of the Art Fuel Cell Technologies for Distributed Generation* (2000) by Robert Braun, Sanford Klein, and Douglas Reindl, University of Wisconsin-Madison.

Long-term employment effects of the alternative system improvements

The above reliability analysis focused on the direct economic costs of operating 1,560 MW of electric generation versus usage of 1,470 MW of purchased power using the Arrowhead-Weston Transmission Project. The following analysis examines the long-term employment effects in Wisconsin of building either the Arrowhead-Weston project, conventional combustion turbine and combined cycle electric generation, or using renewable resources such as wind and biomass for electric generation. Construction employment effects are not considered due to their transitory nature. While construction effects are important and can be large in size, the long-lived nature of either generation or transmission requires concentration on the more permanent employment effects of the different alternatives.

With respect to the Arrowhead-Weston line, the long-term employment change in Wisconsin is negligible. The annual cost of operation and maintenance for the line is expected to be $350,000. At this level of expenditure, the overall direct and indirect job impact would likely be between 0 and 5 full-time job equivalents in Wisconsin. This estimate is based on an average Wisconsin employment multiplier of 10.3 full time jobs per million dollars of utility expenditure.[121] Direct jobs refer to the actual number of employees involved in a specific project; indirect job creation, sometimes referred to as a multiplier effect, occurs due to the spending activities of those persons holding the direct jobs.

With respect to using 1,560 MW of conventional natural gas fired electrical generation, the long-term employment change in Wisconsin is small. The overall direct and indirect job impact would likely be between 50 and 80 full-time job equivalents in Wisconsin. This estimated range is the result of using the direct job impacts associated with recent proposed power plants in Wisconsin. The proposed 1,050 MW combined cycle BadgerGen power plant in Kenosha county is expected to create up to 35 permanent full-time jobs.[122] The proposed 450 MW combustion turbine RockGen Energy Center in Dane County is expected to create four permanent full-time jobs.[123] In addition to these 39 direct jobs at the power plants, there would also be indirect jobs created in the Wisconsin economy. This analysis assumes that the indirect job effect could be as large as the direct effect.

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[121] Page 121, Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System, Bureau of Economic Analysis, U.S. Department of Commerce, May 1986.

[122] Page 93, Final Environmental Impact Statement, Badger Generating Company, LLC Electric Generation and Transmission Facilities, Docket 9340-CE-100, PSCW, June 2000.

[123] Page 39, RockGen Energy Center Environmental Impact Statement, Docket 9335-CE-101, PSCW, October 1998.

Turning to the employment effects of renewable resources, it has been estimated that renewable energy systems create one more job per gigawatt hour of electric generation than conventional power plants.[124] For 3,400 hours of operation, 1,560 MW of renewable electric generation would create 5,304 gigawatt hours of electricity in one year. Given the estimated job impact per gigawatt hour, it is possible that the use of 1,560 MW of renewable energy resources could create around 5,300 additional jobs in Wisconsin above that created by conventional power plants using fossil fuels. (See Table 4-18.) A 1992 study by the New York State Energy Office showed that on a watt for watt basis, wind power creates 66 percent more jobs than natural gas-fired generation and 27 percent more jobs than coal-fired electricity generation. The reason that the use of renewable resources would create more jobs in Wisconsin than the use of the Arrowhead-Weston Transmission Project or conventional fossil fuel generation is that money currently used for the purchase of energy over the transmission grid or fuel for coal or gas power plants from out-of-state sources would no longer leave the state. Such resources would remain circulating inside the state, thereby creating the additional jobs.

Table 4-18 Direct and indirect jobs created in Wisconsin by 1,560 MW of conventional and renewable resources electric generation versus the Arrowhead-Weston Transmission Project project

Supply Option	Direct and Indirect Jobs
Arrowhead-Weston Project	0 to 5
Conventional power plants	50 to 80
Renewable resources	Up to 5,380

Table 4-18 provides first-round employment estimates and should be used with caution. This is because the analysis incorporates the overall price assumption that under the Arrowhead-Weston project and conventional generation, electric power would cost ratepayers the same amount and that power supplied by renewable resource electric generation would be 8 percent more expensive.[125] Cost comparisons in prior sections indicated that wind and biomass electric generation would be more than 8 percent more expensive than either the Arrowhead-Weston project or conventional generation. Such a premium would create a second-round effect

[124] Page 4, "Fueling Wisconsin's Economy with Renewable Energy," by Steve Clemmer, Energy Bureau, Wisconsin Department of Administration, paper submitted for the proceedings of the American Solar Energy Society's Solar 1995 Conference, July 15-20, 1995. The one additional job per gigawatt hour estimate is based on a portfolio mix of 51 percent wood, 27 percent wind, 9 percent refuse derived fuel, 6 percent hydro, 4 percent biogas, and 3 percent solar.

[125] Ibid. The 8 percent more expensive assumption was made by the DOA study's author.

reducing the relative competitiveness of the state's economy.[126] Attendant job losses would subsequently reduce the estimate of 5,380 jobs.

Environmental review of the Lower-Voltage Reinforcement alternative

Table 4-14 lists the transmission system improvements that are part of the Lower-Voltage Reinforcement alternative and provides some information about the amount of new ROW likely to be required for each improvement. The proposed changes in this option would require rebuilding or upgrading about 131 miles of existing transmission and sub-transmission (46 kV) lines. Minimal, if any, new ROW would be required for most of these upgrades. About 40 miles of new line could be double circuited with existing facilities. The addition of some of these new lines could require an expansion of the existing ROW. Finally, the Lower-Voltage Reinforcement alternative includes four new transmission lines (Chisago-Apple River, Sunrise Tap-McCue, Hillsboro-Reedsburg and Maine-Brokaw) resulting in about 66 miles of new construction in Wisconsin. A portion of several of these new transmission lines could also be double circuited with existing lines.[127]

The Commission has already approved the Chisago-Apple River transmission line. The voltage, line design, and route of this line are currently under mediation. Routing considerations include placing portions of the line underground within the cities of Taylors Falls and St. Croix Falls and corridor-sharing with roads or existing transmission facilities over much of the total length of the line. Opportunities to reduce the impacts of this line on important natural resources, such as the St. Croix NSR, and the human environment could be substantial if interested parties can reach an agreement.

WP&L expects to file a CPCN application with the Commission soon for the 10-mile long 138 kV Sunrise Tap – McCue line. In addition to the incidental benefit of increasing transfer capability, this line is proposed to meet growing electric demand in the Janesville area. Several of the routes discussed at public meetings held earlier this year include corridor sharing with roadways and other transmission facilities.

The 28-mile long Hillsboro – Reedsburg 161 kV line was included in WP&L's SEA filing. WP&L's AP-8 filing indicates that this line is needed within the next three years to alleviate the risk of low voltages and line overloads in the Reedsburg area. The primary land use between

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[126] The converse is also true, implying that selection of the most cost effective option ultimately produces the most desirable second round competitiveness effect.

[127] The route for the Chisago-Apple River line approved by the Commission and the route variation currently under mediation by the interested parties include a minimum of eight miles of double circuit construction. There is also a potential for double circuiting a portion of the Hillsboro-Reedsburg line.

Reedsburg and Hillsboro is agricultural and the terrain is fairly hilly. It may be possible to utilize an existing transmission line ROW for nearly half of the 28-mile distance.

An application for the Maine-Brokaw 115 kV line is expected in October 2000 (this line would be initially operated at 46 kV). This line would be one to two miles long, and would cross the Wisconsin River. This crossing could be adjacent to a county trunk road or at another less developed location.

Because the primary need for all of the transmission improvements (shown in Table 4-14) that require new ROW is tied to local area support and reliability, the environmental impacts associated with their construction are equally likely to occur with or without approval of the proposed Arrowhead-Weston Transmission Project. The environmental impacts of the proposed Arrowhead-Weston line (or another EHV line) would be in addition to those associated with the transmission improvements. If the planned facilities that comprise the Lower-Voltage Reinforcement alternative can substantially improve Wisconsin's ability to import power with modest environmental effects, then the incremental transfer capability provided by the Arrowhead-Weston Transmission Project may be small in comparison to the amount of environmental harm it would cause.[128]

Table 4-19 shows the potential environmental impacts of the Lower-Voltage Alternative and the proposed Arrowhead-Weston Transmission Project.[129] The ranges are indicative of a "best-case" and "worst case" scenario, i.e. under a best case scenario the Arrowhead-Weston line would have 120 miles of double circuiting and 155 miles of new corridor construction. The broad categories indicating the level of impact expected are generalizations. For example, a rebuild of an existing transmission line within an established corridor may cause more impact if the ROW passes through large wetlands that are not easily accessible. Conversely, new construction adjacent to a road ROW in open pasture or cropland may have minimal environmental effects.

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[128] A preliminary analysis indicates that the Lower-Voltage Reinforcement alternative could provide about 80 percent of the import capability associated with the Arrowhead-Weston 345 kV line.

[129] The values shown for the Arrowhead-Weston Transmission Project represent a 345 kV line from Oliver to the Weston Substation via the Tripoli Sector, and a 115 kV line from Tripoli to the Highway 8 Substation in Rhinelander. This is the applicants' preferred routing for the 345 kV line.

Table 4-19 Comparative environmental summary

	Upgrade/Rebuild - Little or No New Impact (Miles)	Double Circuit- Minimal New Impact (Miles)	New Construction- Substantial Impact (Miles)*
Lower-Voltage Reinforcement alternative	46	48-54	40-54
Arrowhead-Weston Transmission Project	0	69-120	155-206

* Length (miles), rather than area (acres), is used in this analysis because the ROW width required for construction of some of the lines associated with the Lower Voltage Reinforcement alternatives is not known.

Environmental summary of the integrated alternative

The overall biological and socioeconomic effects related to the construction of one (or more) of the generation facilities described earlier and the Lower-Voltage Transmission Reinforcements would be less than those related to construction of the Arrowhead-Weston Transmission Project. The amount of land disturbed, the number of people affected, the level of human and social impacts on private and public property, and the potential damage to the natural environment are likely to be greater for the Arrowhead-Weston Transmission Project than for other system alternatives described in this chapter.

There is a high likelihood that at least some of the new generation proposals discussed early in this chapter will be constructed within the next 7 to 10 years. This construction, in addition to the transmission system improvements identified in AP-8 and the SEA, and advances in energy efficiency, distributed generation and renewable resources, could potentially provide a viable integrated alternative to the proposed project without causing the significant incremental environmental impacts of the Arrowhead-Weston Transmission Project.

Summary of alternative system improvements

Several individual non-transmission options were analyzed to compare their cost and performance with the proposed high-voltage transmission line. No single option discussed was both cost competitive and able to fully replace the capacity provided by the proposed line.

- Energy efficiency might be cost competitive but the level available is uncertain. Additional analyses may be performed by an intervenor and presented in this case.
- RTP could potentially provide 258 MW of capacity. The associated cost is unknown.
- Several conventional, distributed, and renewable resource generation technologies were analyzed. In all cases using current purchase power costs, at capacity levels

equal to that provided by the proposed transmission line, and under both the LOLE and pure capacity reliability perspectives, customers or ratepayers would pay more for generation options. Using expected 2010 purchase power costs, the proposed transmission line could be a cost-effective option although that is not guaranteed. In the future, electric power supply should be available for import from MAIN but may be significantly less so from MAPP during summer peak conditions.

- Environmental costs and benefits were not factored into the economic analysis of any alternative.

As a result of recent changes in industry structure and laws governing regulatory oversight, there is no longer a mechanism that facilitates an integrated approach using generation, transmission, and energy-efficiency alternatives. Neither the Commission, nor any other single entity has the ability to implement all of the individual pieces of an integrated alternative. Nonetheless, if a combination of merchant power plant generation, assorted smaller transmission projects, real-time pricing, distributed resources and energy efficiency efforts could be achieved, it might be able to address many of Wisconsin's reliability concerns that the proposed Arrowhead-Weston transmission project is intended to remedy.

Several electric generation projects, proposed mostly by IPPs, are currently under consideration in Wisconsin. If a significant amount of generation capacity is built in Wisconsin, then it could contribute to an alternative that combines generation, transmission, efficiency and pricing measures. However, Wisconsin's experience with IPPs, while limited, suggests that many of these developers may encounter difficulty in bringing their plans to fruition.

Commission staff's analysis of a set of lower-voltage transmission reinforcements indicates that significant improvements in transmission transfer capability, relative to today's system may be achievable. This result is preliminary, however, in that Commission staff did not conduct the dynamic stability analysis of this alternative that would be necessary to confirm these results.

Given the uncertainty about the degree to which the Lower-Voltage Reinforcement transmission alternative could alleviate the need for additional generation, Commission staff did not prepare a cost estimate for an integrated alternative. An accurate construction cost estimate would require not only a good estimate of the amount of generation needed, but also information from the utilities whose facilities would be affected by the Lower-Voltage Reinforcement transmission upgrades. Given the absence of a comprehensive integrated planning process, this information is not available to the Commission.